NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #15-2
June 23, 2015 10:00 a.m. – 5:00 p.m. EST
June 24, 2015 8:00 a.m. – 3:00 p.m. EST
Hampton Inn & Suites Saratoga Springs Downtown Hotel
25 Lake Avenue
Saratoga Springs, New York
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 28840965**

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated April 29, 2015
NPCC Glossary of Terms, dated January 18, 2012

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams
3.2 Executive Tracking Summary
3.3 NERC Project Tracking Spreadsheet

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion / Approval

5.1 NERC Weekly Standards Bulletin
5.2 Approval of RSAR Regional Variance -PRC-006-3--Automatic Underfrequency Load Shedding - Variance for the Quebec Interconnection
5.3 NERC IGTF Report
5.4 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
5.5 FERC NOPR of GMD HQT Presentation
5.6 TOP-IRO NOPR RM15-16-000
Mr. Ben Li will call in at 2PM to discuss the issue.

6.0 NERC Reliability Standards

http://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer	6/23/15 Call-In
2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East, IRO-009	7/8/15 (F)	7/8/15 (I)	Katherine Street Greg Campoli	1:00PM
Project 2015-04 Alignment of Terms	7/13/15 (F)	7/13/15 (I)	Lacey Ourso	1:15PM
Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	7/10/15 (I)			
Project 2014-01 Standards Applicability for Dispersed Generation Resources	7/13/15 (I)			
Project 2015-07 Internal Communications Capabilities	7/15/15 (I)			
Comments: (I) – Informal; (F) – Formal **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

6.2 Ballot History (Since last RSC Meeting)

6.3 Comment Form History (Since last RSC Meeting)

7.0 NERC Drafting Team Nominations

http://www.nerc.com/pa/Stand/Pages/Drafting-Team-Vacancies.aspx

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation For Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

https://www.npcc.org/Standards/default.aspx

8.1 Current Activities:

8.1.1 Disturbance Monitoring Standard PRC-002-NPCC-01 Comparison

8.1.2 Approval of RSAR for Automatic Underfrequency Load Shedding PRC-006-NPCC-1. Requester: Brian Robinson.

8.2 Activities on Hold: Regional Standard BAL-002-NPCC-01: Regional Reserve Sharing

9.0 NPCC Non-Standards

https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

9.1 Directories:

9.1.1 Directory #1 Design and Operation of the Bulk Power System (Status of CO7/CP11 Review).

9.1.2 Directory #7 SPS (Status of NERC RAS)

9.1.3 Directory #9 and #10 Generator Verification (status of TFCO Review)

9.1.4 Directory #4 System Protection Criteria (status of TFSP Review)

9.1.5 Directory#8 System Restoration (status CO11 Review)

9.2 Discussion topic: Criteria Considerations for Emerging Risks

10.0 RSC Member Items of Interest

10.1 RSC Roster

11.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

11.1 NERC Filings to FERC
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.2 FERC Orders / Rules
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.3 Federal Register
https://www.federalregister.gov/

11.4 FERC Sunshine Act Meeting Notice

11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

12.1 Standards Committee (SC)
http://www.nerc.com/comm/SC/Pages/default.aspx

January 21st - Call	February 18th - Call	March 11th - Meeting
April 15th - Call	May 20th - Call	June 10th - Meeting
July 15th - Call	August 19th - Call	September 23rd Meeting
October 21st - Call	November 18th - Call	December 9th - Meeting

12.2 Standards Committee Process Subcommittee (SCPS)
http://www.nerc.com/comm/SC/Pages/Standards%20Committee%20Process%20Subcommittee%20SCPS/Standards-Committee-Process-Subcommittee-SCPS.aspx

12.3 Standards Committee Project Management and Oversight Subcommittee (PMOS)
http://www.nerc.com/comm/SC/Pages/ProjectManagementandOversightSubcommittee(PMOS).aspx

12.4 Member Representatives Committee (MRC) Meeting
http://www.nerc.com/gov/bot/MRC/Pages/AgendaHighlightsandMinutes2013.aspx

12.5 Board of Trustees (BOT) Meeting
http://www.nerc.com/gov/bot/Pages/Agenda-Highlights-and-Minutes-.aspx

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Pages/AgendasHighlightsandMinutes.aspx

13.0 NERC Items of Interest (Since last RSC Meeting)

13.1 Lessons Learned
http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx

13.1.1 Two new Lessons Learned have been issued since the last RSC meeting.

13.2 Alerts

http://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx

There has been one new NERC Alert released since the last RSC meeting.

13.3 2015 ERO CMEP Implementation Plan Version 1.1

13.4 Final CIP V5 RSAW Released; Transition Resources Updated

13.5 NOPR on Transmission System Planned Performance for GMD Events Reliability Standard

13.6 State of Reliability 2015

13.7 Notice of Proposed Revisions to NERC Rules of Procedure Section 302.1, 400, Appendices 2, 4C, 5A and 5B

14.0 Other Items of Interest

14.1 2015 Regional Entity Business Plans and Budgets

14.2 NPCC Compliance Committee (CC)

January 14th – Call	February 18th – Call	March 17-18th Meeting
April 15th – Call	May 13th – Call	May 19-21st Workshop
June 16-17th Meeting	July 15th – Call	August 19th – Call
September 22-23rd Meeting	October 14th – Call	November 10-12th Workshop
December 3-4th Meeting		

14.3 NPCC Board of Directors Meeting (BOD)

February 3rd-4th Meeting	March 25th – Call	April 29th Meeting
June 4th – Call	June 25th Meeting	August 5th - Call
September 8th-9th Meeting	October 28th – Call	December 2nd Meeting

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2015 Meeting Dates

February 18th-19th, 2015 NextEra Energy Offices, Juno Beach FL
April 22th & 23th, 2015 Dominion Offices, Richmond VA
June 23rd & 24th, Saratoga NY
October 7th & 8th, Montreal Quebec
December 3rd & 4th, Albany NY

15.2 RSC 2015 Conference Call Schedule (calls can be scheduled as needed)
all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 29086775)

January 16	January 30	February 13
March 6	March 20	April 2
May 1	May 15	May 29
June 12	July 10	July 23
August 14	August 28	September 11
September 25	October 23	November 6
November 20	December 18	

Respectfully Submitted,

Guy V. Zito, Chair RSC
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #15-2
April 22, 2015 10:00 a.m. – 5:00 p.m. EST
April 23, 2015 8:00 a.m. – 3:00 p.m. EST
Dominion Resources Services, Inc. Office
120 Tredegar St
Richmond, Virginia USA
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 28840965**

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated March 3, 2015
NPCC Glossary of Terms, dated January 18, 2012

Attendees:

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1 & 2	
2.	Lee Pedowicz	Northeast Power Coordinating Council		1 & 2	
3.	Gerry Dunbar	Northeast Power Coordinating Council		1 & 2	Via Phone
4.	RuiDa Shu	Northeast Power Coordinating Council		1 & 2	
5.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	
6.	Mark J. Kenny	Eversource Energy	1	1	Via Phone
7.	Jim Grant	New York Independent System Operator	2	1 & 2	
8.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	1	1 & 2	
9.	Bruce Metruck	New York Power Authority	5	1 & 2	
10.	Bob Coughlin Proxy for Kathleen Goodman	ISO-NE	2	1 & 2	Via Phone
11.	Si Truc Phan Sector 1 Proxy for Sylvain	Hydro-Québec TransÉnergie	1/2	1 & 2	

	Clermont				
12.	Chantal Mazza	Hydro-Québec TransÉnergie	2	1 & 2	Via Phone
13.	Vincent Morissette	Hydro-Québec TransÉnergie	Guest	2	Via Phone
14.	Brian Robinson	Utility Services	5	1	
15.	Brian Shanahan	National Grid	1	1 & 2	
16.	Michael Jones	National Grid	3	1 & 2	
17.	Payam Farahbakhsh	Hydro One Networks	1	1 & 2	
18.	Adnan Jabbar Proxy for Helen Lainis	Independent Electricity System Operator	2	1 & 2	
19.	Connie Lowe	Dominion Resources Services	4	1 & 2	
20.	Glen Smith	Entergy Services, Inc.	4	1 & 2	
21.	Ron Falsetti	AESI	Guest	1 & 2	
22.	Joel Charlebois	AESI	Guest	1 & 2	

Introductions and Chair's Remarks

Guy Zito called the meeting to order at 10:00 a.m. on Wednesday April 22, 2015.

He introduced Lisa Moerner, Director of FERC, and Electric Market & NERC Compliance Policy at Dominion Resources Services.

Lisa Moerner welcomed the meeting participants and provided a short introduction to Dominion Resources Services.

Connie Lowe discussed the emergency evacuation procedures for the building and provided logistics for the meeting.

Guy Zito thanked Bruce Metruck and Si Truc Phan for accepting the roles of RSC vice chairs and noted their appointments had been approved by the NPCC Board of Directors.

NPCC Antitrust Compliance Guidelines

The NPCC Antitrust Compliance Guidelines were read by Lee Pedowicz.

Agenda Items:

1.0 Review of Agenda

The RSC Draft Meeting Agenda was reviewed by Guy Zito.

Guy Zito transferred 5.10 Draft ERO Event Analysis Process and Appendices – Version 3 to Section 14.4 on the RSC Draft Meeting Agenda.

Guy Zito adding an additional topic in Section 6.4 Vincent Morissette called in at 9:00 a.m. on Thursday April 23, 2015 to present Quebec's Variance for PRC-006-2.

Guy Zito removed Section 13.0 from future RSC meeting agendas.

Guy Zito added Section 5.11 to the Agenda for Jim Grant to discuss how the NYISO is going to address TOP registration issues for NY TOs and to explain how the Coordinated Functional Registrations would work.

2.0 RSC Meeting Minutes

Approval of Minutes: Final Meeting Minutes 2-18-15

Guy Zito suggested replacement language for the unresolved issue addressed in Section 5.3.Herb Schrayshuen suggested a revision to what was proposed.

Brian Robison made a motion for approval of the Minutes as revised.

Si Truc Phan seconded the motion.

The Meeting Minutes were approved as read.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams

John Ciufo from Hydro One has retired and needs to be removed from the NERC Standard Drafting Teams list. Mike Potishnak will be unable to continue on the BAL projects past this coming June. The importance of keeping the list up-to-date was stressed.

It was agreed to follow a suggestion made by Herb Schrayshuen to only include those projects that have not been finally approved.

Action Item: NPCC Standards Staff will review the Drafting Team list to ensure it is kept up-to-date.

3.2 Executive Tracking Summary

RuiDa Shu provided updates on the Executive Tracking Summary which is posted on the NPCC Website.

Guy Zito mentioned that at this time there is an indication there will be another "bow wave" of projects posted at the end of the year. NERC realizes this, and they will try and have some completed sooner, by August. With that accelerated schedule it will difficult to have the time to address standards' issues that arise.

3.3 NERC Project Tracking Spreadsheet

Guy Zito provided a brief update on the NERC Project Tracking Spreadsheet.

4.0 Open Action Items

4.1 Open Action Items List

Guy Zito provided updates on the Open Action Item list. Mike Jones reported that Compliance Committee members agreed that entities should send in their comments on RSAWs individually--there won't be a coordinated and consensus NPCC Compliance Committee submittal. How NPCC as a region will comment on RSAWs going forward remains an unresolved issue. Guy Zito will continue to pursue this

with NPCC Leadership. It was mentioned that NERC has been writing the RSAWs with little help, if any, from the drafting teams. .

Si Truc Phan said that Hydro-Quebec cannot share comments on RSAWs though CC. Guy Zito suggest to ensure individually someone in your organization is reviewing or cognizant of these postings directly to NERC.

Herb Schrayshuen asked what committee this issue should be brought to.

Guy Zito said that there is a gap in RSAW development, and the Compliance Committee does not believe it is in their role to pursue it. Questions asked were what the value in reviewing RSAWs is, and what is the value in sending in comments individually?

Ron Falsetti added that that the NPCC Board of Directors should make a decision on who should author comments on the RSAWs. The RSC Scope approved by the Board of Directors does not include RSAW review.

Item 4.2 NPCC outreach is removed from the Open Action Item List.

Item	Description	Owner	Due	Status
4.1	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Ongoing Guy Zito decided to keep RSAWs for now.

5.0 Items Requiring RSC Discussion / Approval

5.1 NERC Weekly Standards Bulletin

Guy Zito mentioned this was an information item only.

5.2 NPCC RCC Meeting Minutes

Guy Zito recommended that Section 5.2 NPCC RCC Meeting Minutes be removed from the RSC Meeting Agendas going forward and that only pertinent standards or criteria related topics in the RCC meetings be related to the RSC members.

5.3 Primary RSC Members can't serve as Alternates in other sectors

Guy Zito said that this was an issue that was exposed by the recent revision to the Regional Delegation Agreement. Although there is no direct violation of the NPCC Revised and Restated Bylaws the matter has been resolved voluntarily by NPCC working with the members of the RSC.

5.4 Renegotiation of Regional Delegation Agreements

Guy Zito provided a brief description on the renegotiation of the Regional Delegation Agreement (RDA) document. An NPCC Regional Delegation Agreement will be good for five years, but can be extended to ten years. Further clarification for the Canadian relationships will be part of the new RDA.

5.5 Validation Testing of Minimum Vegetation Clearance Distances

Guy Zito provided additional information on the FAC-003 Research Project. This is a RAPA item and a study directed by the FERC indicated that the clearances as specified in the FAC-003 standard need to be increased. The current Gap Factor in the "Gallet" equation used for determining clearance to prevent flashover to vegetation needs to be reduced to 1.0 from 1.3. This will result in increased clearance of from 1.5 to three feet. Ron Falsetti said that a draft alert was sent out several days before this meeting. Not everyone got it. A SAR will be posted eventually to revise the clearance tables in the standard and a NERC Alert issued as well to notify the industry. It was noted that Compliance would audit only to the standard, not the Alert, SAR or study performed by RAPA.

5.6 NYPA Comments on CIP-002-5.1 Lessons Learned

Bruce Metruck provided updates on CIP-002-5.1 Lessons Learned. The issue was brought to the Compliance Committee and the RCC. In addition, meetings were held with NERC and NPCC staff. The issue is that when looking at any entity the RC, TOP, or BA are the ones that actually have to perform the analysis. NERC is considering developing a SAR to address this. Herb Schrayshuen suggested that industry should write the SAR. The SAR would address the definition of Control Center. The local control center issue still exists. Guy Zito said that with the standard already published, a SAR should not be perceived as weakening it. Suggested that an industry trade organization, such as CEEI, or APPA for example, should get involved. Bruce Metruck said that there was a meeting taking place today (April 22, 2015) where this issue is being addressed. It was his expectation something to be released today (April 22, 2015).

Brian Robinson indicated that there will be a communication sent out by NERC on this topic.

5.7 Review of the Documents on RSC NPCC Website

RuiDa Shu led the discussion. People had questioned where documents could be found on the NPCC Website. In response to an inquiry from Si Truc Phan, it was reported that all standards documents are public and entities don't have to be a member of NPCC to view the documents.

5.8 Project 2007-06.2 Phase 2 of System Protection Coordination

RuiDa Shu led the discussion. The Drafting Team is at point where a decision has to be made as to how the project is to be moved forward. Guy Zito said that the term "familiarity with protection systems" is a concern, and that FERC has been involved. RuiDa Shu will distribute an explanatory white paper when it becomes available (within several days after the RSC Meeting concludes). Ron Falsetti opined that the issue of demonstrating familiarity or knowledge of protection systems would be more appropriate in a PER standard.

5.9 Periodic Review Project 2010-14.2 BAL-005-0.2b and BAL-006-3

Guy Zito mentioned that the content of BAL-005 was moved into other standards. Si Truc Phan commented that BAL-006 involves commercial customers and it is not a reliability issue. BAL-005 should be looked at with respect to Paragraph 81. BAL-005 contents were put into BAL-001, and BAL-002.

5.10 Draft ERO Event Analysis Process and Appendices – Version 3

Brian Robinson indicated that draft document is posted for comment until May 30th, 2015.

Guy Zito said that RSC won't be submitting comments for this.

5.11 Jim Grant will provide a brief discussion on new TOP issues at NYISO.

Jim Grant led the discussion. The NYSIO-TO Agreement outlines what facilities it has operational control over. The TOs were required to give notification of what they operated. New facilities had to be added. The NYISO met with RCs to determine how this should be handled. Not everything is A-1. The TOs would be TOPs. Changes to how things are being done was minimized. There were minor changes made to the NYISO-TO Agreement. This takes effect July 1, 2016. The NYISO is prepared to enter into a Coordinated Functional Registration (CFR) agreement. The NYISO is now the TOP for only the A-10 list.

Bob Coughlin said that there are no new TOPs in New England. He sees no problems with adopting the new BES.

Jim Grant further indicated that to register as a TOP, a certification is required. New TOPs have to register by July 1st, 2015. By the end of 2015 all New York TOs should be certified as TOPs.

The NYISO will assume some of the 200KV TOP responsibilities.

5.12 Scott Nied from NPCC Compliance staff called in at 1p.m. to discuss compliance items, and risk-based registration. Scott will be working with TFSP, TFCP, TFCO and TFSS on risk-based registration and is also seeking the Canadian provinces to provide statement how their final BESs will support reliability.

Scott Nied also discussed the BES definition implementation.

Each of the NPCC Task Forces will provide a report on the impact of BES Elements on each Canadian providence.

6.0 NERC Reliability Standards

http://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer	4/22/15 Call-In
Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations			Scott Barfield-McGinnis	
Project 2014-04 Physical Security			Stephen Crutchfield	
Project 2007-06 System Protection Coordination	5/15/15	5/15/15	Al McMeekin	

	(F)	(A)		
Project 2015-02 Emergency Operations Periodic Review	5/11/15 (I)		Laura Anderson Chair: David McRee	1:45 p.m.
New Standards Balloting and Commenting System			Barbara Nutter	2:00 p.m.
Comments: (I) – Informal; (F) – Formal **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Guy Zito mentioned that RSC recommended a yes vote for Project 2008-02.2.

Lou Oberski, the Chair of Project 2014-04 Physical Security, called into the meeting at 1:20 p.m. The Standard Drafting Team's target goal is to complete the project by October 1st, 2015 to address one of the FERC Directives. Suggestions were made to the SDT on an alternative word for "Widespread", which the FERC indicated needed to be removed from the standard. The Drafting Team removed the term "widespread" and did not attempt to clarify or replace the concept. The SDT has also made minor revision to the VRF and VSL tables. Don't have consensus though. Will be worked on after the final ballot.

The RSC reviewed Project 2007-06 PRC-027 as a group and identified no major issues. Guy Zito indicated that the project was posted for comment and an additional ballot would be held which would end on May 15, 2015.

David McRee, Chair of the SDT for Project 2015-02 called into the RSC meeting at 1:29 p.m. Attachment 1 was clarified in EOP-004-2. EOP-005-2 has requirements identified for retirement. EOP-006-2 has Parts 1.2, 1.3, and 1.4 identified for retirement. EOP-008 includes revisions to the Measure.

Posted for comments until May 11th, 2015. The SDT tried to retire all the redundant requirements. The SDT will use rationale boxes to address all the "soft" directives by FERC. If needed, a SAR will be included with the Project. The SDT is looking for industry comments specifically on the training portion of the EOP-005 and EOP-006 standards.

Connie Lowe led the discussion on the requirements for training in EOP-005-2, and EOP-006-2. The RSC mentioned training should be in PER-005.

Si Truc Phan asked if the Hydro Quebec requested change was made in the Attachment to 2000MW in reference to the Quebec variance, and David McRee indicated he thought that it was.

Barb Nutter from NERC called into the meeting at 1:55p.m. She led the discussion on NERC's new Standard Balloting System (SBS).
The new SBS has been in effect since February, 2015. NERC is working on being able to allow the site to make all comment submissions more easily visible. NERC is also working on having the system recognize the 8:00 p.m. submission close deadline. Barb indicated that the comment submission issue should be fixed by next week.

Barb Nutter noted that if a standard is posted for comment with no ballot, then comments can only be submitted once. If a Standard is posted with a ballot, then the commenter may resubmit the entire comment form.

Action Item: Lee Pedowicz needs to come up with a way to identify the group names in the Balloting and Commenting System.

6.2 Ballot History (Since last RSC Meeting)
Rui Da Shu reviewed the Ballot History.

6.3 Comment Form History (Since last RSC Meeting)
Rui Da Shu reviewed the Comment Form History document in the meeting.

6.4 Hydro-Quebec Variance for PRC-006-2.

6.5 PRC-012-2 - Remedial Action Scheme Review Procedure
Guy Zito discussed this item. Greg Campoli and others called in from the ISO/RTO Council Standards Review Subcommittee Meeting to discuss the draft standard and the drafting team's position. The main topic of discussion was the expanded potential role of the RCs in the review of the RAS. The existing SPS standards have the Regional Reliability Organization (RRO) listed as an applicable entity. Guy Zito noted that FERC, in Order 693 had ruled that the RRO, as listed in the standard, had a "fill-in-the-blank" aspect. Also discussed was the security vs. reliability issues associated with the SPS/RAS. It was the opinion of the ISO/RTO SRC that the PC was the more appropriate entity to conduct RAS reviews.

Vincent Morissette from Hydro Quebec called into the RSC Meeting at 9:00 a.m. April 23, 2015 to present the SAR for a Quebec Variance to continent-wide PRC-006-2 Automatic Underfrequency Load Shedding.

Action Item: NPCC Standards Staff will review the SAR submitted by Hydro Quebec and work to finalize it. NPCC will then transmit the SAR to NERC and be a joint "requester."

7.0 NERC Drafting Team Nominations

http://www.nerc.com/pa/Stand/Pages/Drafting-Team-Vacancies.aspx

7.1 Currently Posted Drafting Team Vacancies
- 7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)
- 7.2.1 None at this time

7.3 Solicitation For Informal Development Teams
- 7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

https://www.npcc.org/Standards/default.aspx

8.1 Current Activities:

8.1.1 RSAR for Disturbance Monitoring Standard PRC-002-NPCC-01 SDT Roster

Guy Zito asked for a motion to approve the SDT Roster for the RSAR on PRC-002-NPCC-01.

Brian Robinson made a motion for approval.

Glen Smith seconded the motion.

The SDT Roster for Disturbance Monitoring PRC-002-NPCC-01 was approved as submitted.

8.1.2 RSAR for Automatic Underfrequency Load Shedding PRC-006-NPCC-1

Brian Robinson is the Requester of the RSAR.

Kelly Dash and Mike Jones both provided changes/updates to the RSAR for Automatic Underfrequency Load Shedding PRC-006-NPCC-1.

Action Item: NPCC Standards Staff will review the RSAR with the changes suggested and handle appropriately. The final RSAR will be brought to the RSC for approval at the June 2015 meeting

8.2 Activities on Hold: Regional Standard BAL-002-NPCC-01: Regional Reserve Sharing

9.0 NPCC Non-Standards

https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

9.1 Directories:

9.1.1 Directory #1 Design and Operation of the Bulk Power System (Status of CO7/CP11 Review).

Current Status: update on Mr. Dunbar's 1/26/15 email message to the RSC (List of ERO Standards in each Directory).

The CO7/CP11 Working Group reviewing Directory#1 has proposed removing the list of ERO standards associated with Directory#1 from the document. RSC has been asked to consider whether such lists should also be removed from all other NPCC Directories.

RSC requested the development of a list that would allow the RSC to consider the pros and cons of removing the list of associated ERO standards from all NPCC Directories.

Gerry Dunbar reviewed the pros and cons list with the RSC members.

Herb Schrayshuen suggested adding another con to the list: maintaining the ERO Standards list in their associated directories will be an additional administrative burden on the NPCC Standards Staff.

Mr. Zito conducted an informal poll of the RSC Members. There was majority agreement to leave the list of associated ERO standards in Directory #1 and all other NPCC Directories.

9.1.2 Directory #3 Maintenance Criteria for BPS Protection – (Retired effective April 1st, 2015 to coincide with the enforcement date of PRC -005-2 *Protection System Maintenance*.).

9.1.3 Directory #7 SPS (Status of NERC RAS)

Mr. Zito discussed the status of Project 2010-05-3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) PRC -012-2. Mr. Zito stated that the revised standard will be impactful for RSC Members and in particular the Reliability Coordinators (R.C.s).

The standard drafting team (SDT) is proposing that the R.C. be assigned applicability for reviewing and approving protection systems classified as a RAS.

Mr. Zito noted that currently NPCC Task Forces perform this review/ approval and there is concern that the R.C. may not have the expertise to adequately consider all aspects of a RAS design.

NPCC is participating as an observer on the drafting team and HQT is also represented and participating on the SDT.

PRC -012-2 will be posted for an informal comment period on April 29th, 2015 in order for the SDT to solicit industry comment and suggestions on the draft standard.

Mr. Zito discussed the issue of redundancy which has been proposed for those RAS that are designed to achieve compliance with the TPL standards.

Mr. Zito suggested that the redundancy requirement has the potential to significantly impact NPCC protection systems currently classified as SPS Type 3.

Members of the ISO-RTO Standard Review Committee (SRC) participated in the discussion. See Item 6.5 above.

Mr. Zito concluded the RAS discussion by stating that NPCC would continue to provide comment and feedback to the SDT as the standard is developed in addition to assessing the standards impact on NPCC's existing SPS criteria (Directory#7).

9.1.4 Directory #9 and #10 Generator Verification (status of TFCO Review)

MOD-25-2 *Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power* has been approved by FERC and is enforceable on July 1st, 2016. NPCC has completed a preliminary comparison between the criteria in Directories #9 and #10 and the requirements in MOD-25-2. TFCO has requested that an ad-hoc working group (CO7) be established to review this comparison and to recommend whether or not the criteria in Directories #9 and #10 should be revised or retired in consideration of MOD-25-2.

9.1.5 Directory #4 System Protection Criteria (status of TFSP Review)

TFSP reviewing document in accordance with the NPCC Reliability Assessment Program (NRAP). TFSP considering comments from the first open process posting and anticipates a second posting of the document.

10.0 RSC Member Items of Interest

10.1 RSC Roster
Action Item: Call Alan McNaughton on requesting another person for Sector 2.

11.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

11.1 NERC Filings to FERC
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.2 FERC Orders / Rules
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.3 Federal Register
https://www.federalregister.gov/

11.4 FERC Sunshine Act Meeting Notice

11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

12.1 Standards Committee (SC)
http://www.nerc.com/comm/SC/Pages/default.aspx

January 21st - Call	February 18th - Call	March 11th - Meeting
April 15th - Call	May 20th - Call	June 10th - Meeting
July 15th - Call	August 19th - Call	September 23rd Meeting
October 21st - Call	November 18th - Call	December 9th - Meeting

12.2 Standards Committee Process Subcommittee (SCPS)
http://www.nerc.com/comm/SC/Pages/Standards%20Committee%20Process%20Subcommittee%20SCPS/Standards-Committee-Process-Subcommittee-SCPS.aspx

12.3 Standards Committee Project Management and Oversight Subcommittee (PMOS)
http://www.nerc.com/comm/SC/Pages/ProjectManagementandOversightSubcommittee(PMOS).aspx

12.4 Member Representatives Committee (MRC) Meeting
http://www.nerc.com/gov/bot/MRC/Pages/AgendaHighlightsandMinutes2013.aspx

12.5 Board of Trustees (BOT) Meeting
http://www.nerc.com/gov/bot/Pages/Agenda-Highlights-and-Minutes-.aspx

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Pages/AgendasHighlightsandMinutes.aspx

13.0 NERC Compliance Tools (Since last RSC Meeting)

13.1 Compliance Analysis Reports (CARs)
http://www.nerc.com/pa/comp/Pages/Compliance-Analysis-Reports.aspx

13.1.1 There have not been any CARs posted since the last RSC meeting

This item to be removed.

14.0 NERC Items of Interest (Since last RSC Meeting)

14.1 Lessons Learned
http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx

14.1.1 Two new Lessons Learned have been issued since the last RSC meeting.

14.2 Alerts
http://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx

14.2.1 There has been no new NERC Alert released since the last RSC meeting.

See Item 5.5 for Vegetation Management.

14.3 Five Year ERO Performance Assessment
Guy Zito requested to remove this topic for future RSC meetings. The members of RSC agreed.

15.0 Other Items of Interest

15.1 2015 Regional Entity Business Plans and Budgets

15.2 NPCC Compliance Committee (CC)

January 14th – Call	February 18th – Call	March 17-18th Meeting
April 15th – Call	May 13th – Call	May 19-21st Workshop
June 16-17th Meeting	July 15th – Call	August 19th – Call
September 22-23rd Meeting	October 14th – Call	November 10-12th Workshop
December 3-4th Meeting		

15.3 NPCC Board of Directors Meeting (BOD)

February 3rd-4th Meeting	March 25th – Call	April 29th Meeting
June 4th – Call	June 25th Meeting	August 5th - Call
September 8th-9th Meeting	October 28th – Call	December 2nd Meeting

16.0 Future RSC Meetings and Conference Calls

16.1 RSC 2015 Meeting Dates

February 18th-19th, 2015 NextEra Energy Offices, Juno Beach FL
April 22th & 23th, 2015 Dominion Offices, Richmond VA
June 23rd & 24th, Saratoga NY
October 7th & 8th, Montreal Quebec

December 3rd & 4th, Albany NY

16.2 RSC 2015 Conference Call Schedule (calls can be scheduled as needed)
all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 29086775)

January 16	January 30	February 13
March 6	March 20	April 2
May 1	May 15	May 29
June 12	July 10	July 23
August 14	August 28	September 11
September 25	October 23	November 6
November 20	December 18	

The meeting adjourned at 10:17a.m. Thursday April 23, 2015.

Respectfully Submitted,

Guy V. Zito, Chair RSC
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

NPCC Representatives on NERC Standards Drafting Teams						
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**
2007-02	Operating Personnel Communications Protocols	Standard	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com
2007-06.2	Phase 2: System Protection Coordination	Standard	RuiDa Shu Po Bun Ear	NPCC Hydro-Quebec TransEnergie	917-934-7976	rshu@npcc.org ear.po-bun@hydro.qc.c
2007-11	Disturbance Monitoring	Standard	Lee Pedowicz	NPCC	212-840-1070	lpedowicz@npcc.org
2007-17.3	Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Standard				
2008-02	Undervoltage Load Shedding	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-01	Training (PER)	Standard	Mark Grear	Constellation	410-470-4380	mark.grear@constellation.com
2010-02	FAC Five-Year Review Team	Standard	John Beck	Con Edison	212-460-4244	beckj@coned.com
2010-03	Modeling Data (MOD B)	Standard				
2010-04	Demand Data (MOD C)	Standard	Andrey Oks	NPCC	212-840-1070	aoks@npcc.org
2010-05.1	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One Networks	647-328-7068	paul.difilippo@hydroone.com
2010-05.2	Special Protection Systems (Phase 2)	Standard	John Ciufo Charles-Eric Langlois	Hydro One Networks Hydro-Quebec TransEnergie	416-345-5258 514-879-4100	john.ciufo@hydroone.com langlois.charles-eric@hydro.qc.ca
2010-13.3	Phase 3 of Relay Loadability: Stable Power Swings	Standard				
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
2010-17	Definition of Bulk Electric System	Standard	Brian Evans-Mongeon Phil Fedora Ajay Garg Jennifer T. Sterling	Utility Services NPCC Hydro One Networks Exelon	802-552-4022 212-840-4909 416.345.5420 630-437-2764	brian.evans-mongeon@utilitysvcs.com pfedora@npcc.org ajay.garg@HydroOne.com jennifer.sterling@exeloncorp.com
2012-09	IRO Five-Year Review	Standard	John Mulhern	Con Edison	212-580-6791	mulhernj@coned.com
2012-13	NUC - Nuclear Plant Interface Coordination	Standard	Kevin Donnelly	Con Edison	914-933-2962	donnellyk@coned.com
2013-03	Geomagnetic Disturbance Mitigation	Standard	Emanuel Bernabeu Kenneth Fleischer Luis Marti	Dominion NextEra Energy Hydro One Networks	804-432-8780 561-691-2456 416-345-5317	emanuel.e.bernabeu@dom.com kenneth.fleischer@fpl.com luis.marti@hydroone.com
2013-04	Voltage and Reactive Control (VAR)	Standard	Sharma Kolluri	Entergy	504-576-4045	vkollur@entergy.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2014-02	Critical Infrastructure Protection Standards Version 5 Revisions	Standard	Greg Goodrich	NYISO	518-356-7591	ggoodrich@nyiso.com
2014-03	Revisions to TOP/IRO Reliability Standards	Standard				
2014-04	Physical Security	Standard	Kathy Judge	National Grid	508-860-6040	kathleen.judge@nationalgrid.com
2015-02	Emergency Operations Periodic Review	Standard	Connie Lowe	Dominion	804-819-2917	connie.lowe@dom.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest	ISO-NE		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the Rul	Standard	Jill Loewer	Utility Services		

Source = NERC Standard Drafting Team Rosters - May 2014

Change Control: Changes Since March 2014:

Projects Removed:

1. Project 2010-13.2, Phase 2 of Relay Loadability: Generation

Projects Added:

1. Project 2014-04, Physical Security
2. Project 2015-02 - Emergency Operations Periodic Review
3. Project 2015-03 - Periodic Review of System Operating Limit Standards
4. Project 2015-04 - Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules
5. Project 2007-06.2 - Phase 2: System Protection Coordination

NPCC Representative Changes:

1. Project 2010-17, Removed Jennifer Dering as the NPCC Representative as she is no longer at NYPA
2. Project 2012-13, Added Kevin Donnelly, Con Edison, as the NPCC Representative
3. Project 2014-03, Added Kyle Russell, IESO, as the NPCC Representative
4. Project 2014-04, Added Kathy Judge, National Grid, as the NPCC Representative

Revised: #REF!

Tab Name	Last Revised	Summary of Changes
NERC RS Exec Tracking Summary	6/5/2015	
NERC RSAWs	6/5/2015	
NPCC RRS Tracking Summary	#REF!	- Regional Standard Processes Manual; Following NPCC BOD approval, NERC posted the proposed NPCC Regional Standard Processes Manual for a 45-day industry review through 8 p.m. Eastern on Wednesday, May 7, 2014
NPCC Doc Tracking Summary	#REF!	- C-00 (Discontinued) - C-05 (Retired) - C-07 (Retired) - C-21 (Retired) - C-44 (Retired)
NPCC Directory Tracking Summary	#REF!	- Directory #1, Design and Operation of the Bulk Power System posted in Open Process - Directory Development and Revision Manual - Comment Response Document posted
NPCC Directory Interpretations	#REF!	- Directory #3 Interpretation on behalf of Hydro One Networks included
Quarterly Filing to NSUARB	#REF!	Annotated worksheet to indicate that "Revisions to D#7 and D#12 approved by the Full Members on 7/9/2013. "

Prior Revision

Tab Name	Last Revised	Summary of Changes

NERC Reliability Standards Executive Tracking Summary

Revised: 6/5/2015

Line No.	Project No. / Title	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
2	2012-INT-07 - Interpretation of CIP-005 for AEP									This interpretation is being prepared for an initial 30-day formal comment period.	
6	Project 2007-06 — System Protection Coordination	PRC-001-3, PRC-027-1	Yes 1st (Thru 7/10/07)	Yes (Formal Thru 5/15/15)	Yes (Additional Thru 5/15/15)						Under Development
8	Project 2007-11 — Disturbance Monitoring	PRC-002-2	Yes 1st (Thru 4/20/07)	NA	Yes (Final 11/6/14)	Yes (11/6/14)	Yes (11/13/14)	Pending for Approval			Under Development
12	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	PRC-005-4	Yes (Informal Thru 3/14/14)	Yes (Formal Thru 6/2/14)	Yes (Inital Thru 6/2/14)						
13	Project 2007-17.4 - PRC-005 FERC Order No. 803 Directive	PRC-005-3	Yes (Informal Thru 4/10/15)	Yes (Informal Thru 4/10/15)							
14	Project 2008-01 — Voltage and Reactive planning and control (Informal Development Project)	VAR-001 and VAR-002	Yes 2nd (Thru 3/26/10)								Under Development
15	Project 2008-02.2 — Phase 2 of Undervoltage Load Shedding	PRC-004-5, PRC-010-2	Yes (Thru 10/9/13)	Yes (Formal Thru 4/7/15)	Yes (Final Thru 4/27/15)						Under Development
18	Project 2009-02 — Real-time Reliability Monitoring and Analys	"New"	Yes 2nd (Thru 2/18/10)	Yes 1st (Informal Thru 4/4/11)						Concept White Paper posted for informal comment period	Under Development
19	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2b, EOP-002-3, EOP-003-1, EOP-004-2 (P81, RBS), EOP-005-2 (P81, RBS), EOP-006-2 (RBS), EOP-008-1 (RBS), EOP-009-1, IRO-001-5	Yes (Thru 12/5/13)	NA	EOP-011-1 Yes (Final Thru 11/6/14)					Project initiated as a 5-year review to clarify scope, avoid potential concurrent revisions to EOP standards (Cold weather SAR)	Under Development
20	Project 2009-04 — Phasor Measurement Units										Project has not started
21	Project 2009-05 — Resource Adequacy Assessments	"New"	Yes 2nd (Thru 3/30/06)								Under Consideration for Development
22	Project 2009-07 — Reliability of Protection Systems	"New"	Yes 1st (Thru 2/18/09)							Pending prioritization - may be postponed	Under Consideration for Development
24	Project 2009-20 — Interpretation of BAL-003-0 R2 and R5 by Energy Mark, Inc.	BAL-003-0.1b	x	x	Yes (Recirc Thru 2/26/10)	Yes (2/26/10)					Under Development
25	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	MOD-031	Yes (Informal Thru 4/1/15)	Yes (Formal Thru 5/19/15)							
27	Project 2010-02 — Connecting New Facilities to the Grid	FAC-001, FAC-002, FAC-003-3, FAC-008-3, FAC-010-2.1, FAC-011-2, FAC-013-2, FAC-014-2	Yes (Informal Thru 1/17/14)	Yes (Formal Thru 5/15/14)	Yes (Final Thru 6/23/14)	Yes (6/23/14)	Yes (8/14/14)	Yes (8/22/14)		Two projects (FAC Review, Project 2010-02) were consolidated and are being initiated as a 5-year review	
28	Project 2010-05.1 — Protection Systems: Phase 1 (Misoperat	PRC-004-3	Yes 1st (Informal Thru 7/11/11)	Yes (Formal Thru 7/9/14)	Yes (Final Thru 8/7/14)	Yes (8/7/14)	Yes (8/14/14)	Pending for Approval		Ballot will be extended one day at a time to achieve a quorum.	Under Development
29	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	RAS Definition	Yes (Informal Thru 3/19/14)	NA	Yes (Final Thru 11/6/14)	Yes (11/6/14)	Yes (11/13/14)	Pending for Approval			
30	Project 2010-05.3 – Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	PRC-012-2	Yes (Informal Thru 4/30/15)	Yes (Informal Thru 5/20/15)							
32	Project 2010-06 — Results-based Reliability Standards	Results-based Reliability Standards Transistion Plan								Transistion Plan posted 7/26/10	
36	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	For Comment (Thru 9/19/10)	Yes (Formal Thru 12/24/14)	Yes (Final Thru 12/1614)						
38	Project 2010-14.1 — Phase 1 of Balancing Authority Reliability-based Control: Reserves	BAL-002-2	NA	Yes (Formal Thru 3/16/14)	Yes (Additional Thru 3/16/15)					As of July 28, 2010 this project has merges Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control into a single project	
39	Project 2010-14.2.2 Phase 2 - Balancing Authority Reliability-based Controls - BAL-004-2	BAL-004, BAL-005-0.1b, BAL-006-2	Yes (Formal Thru 4/15/15)	Yes (Formal Thru 4/15/15)						A 30-day informal comment period for BAL standards (SAR) is now open through 8/14/14.	Under Development
40	Project 2010-16 — Definition of System Operator	NERC Glossary Of Terms	Yes 1st (Thru 12/3/10)	Yes 1st (Thru 12/3/10)							Under Consideration for Development
43	Project 2010-INT-03 Interpretation of TOP-002-2a R2, R8, and R19 for FMPP	TOP-002-2a, R2, R8 and R19								Standards Committee curtailed work in April 2011 - revived in January 2012 to see if a Rapid Revision was feasible. Overtaken by filing of TOP standards.	
45	Project 2012-01 Equipment Monitoring and Diagnostic Devices	FUTURE									
46	Project 2012-02 Physical Protection	FUTURE									
49	Project 2012-08.2 — Phase 2 of Glossary Updates	NERC Glossary Of Terms								Modify existing definition of Transmission Operator and Generator Operator	
50	Project 2012-09 IRO Five-Year Review	Various IRO standards	x	Yes (Thru 9/20/13)						Five year review	Under Development
51	Project 2012-13 NUC - Nuclear Plant Interface Coordination	NUC-001-2.1	Yes (Informal Thru 3/13/14)	Yes (Formal Thru 5/22/14)	Yes (Final Thru 7/3/14)	Yes (Final Thru 7/3/14)	Yes (8/14/14)	Pending for Approval		Five year review	
52	Project 2012-INT-03 Interpretation of CIP-007 for TECO									This interpretation is on hold pending finalization of Project 2012-INT-04 (Interpretation of CIP-007 for ITC).	
55	Project 2013-01 — Cold Weather Preparedness	"TBD"	Draft for Comment (Thru 10/24/12)								
57	Project 2013-03 Geomagnetic Disturbance Mitigation, Stage 2	TPL-007-1	NA	Yes (Formal Thru 11/21/14)	Yes (Final Thru 12/1614)						
59	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	PRC-001-1x1(X), PRC-019-2 and PRC-024-1(X)	Yes (Thru 12/19/13	Yes (Formal Thru 1/22/15)	Yes (Final Thru 3/11/15)						
60	Project 2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions	CIP	Yes (Thru 2/18/14)	Yes (Formal Thru 1/8/15)	Yes (Final Thru 2/2/15)						
61	Project 2014-03 Revisions to TOP and IRO Standards	TOP-001-3	Yes (Formal Thru 3/24/14)	Yes (Formal Thru 1/6/15)	Yes (Final Thru 1/21/15)						
62	Project 2014-04 Physical Security		Yes (Informal Thru 3/28/14)	Yes (Formal Thru 4/9/15)	Yes (Final Thru 4/29/15)						
63	Project 2015-02 Emergency Operations Periodic Review			Yes (Formal Thru 5/11/15)							
64	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3, FAC-011-3 and FAC-014-2		Yes (Formal Thru 6/17/15)							
65	Project 2015-04 Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)		Yes (Formal Thru 4/13/15)	Yes (Formal Thru 4/13/15)							
66	Project 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009		Yes (Informal Thru 4/15/15)	Yes (Formal Thru 7/8/15)	Yes (Initial Thru 7/8/15)						

Acronyms:
SAR- Standards Authorization Request
RS- Reliability Standard
DT- Drafting Team

NERC Reliability Standards Executive Tracking Summary

Revised: 6/5/2015

Line No.	Project No. / Title	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status

SC- NERC Standards Committee
TBD- To Be Determined
BOT- NERC Board of Trustee

NERC Reliability Standard Audit Worksheet (RSAW) Executive Tracking Summary

Revised: **6/5/2015**

ding the individual documents may be found at:
http://www.nerc.com/pa/comp/Pages/Reliability-Standard-Audit-Worksheets-(RSAWs).aspx

RSAW#	Title	Posted for Comment?	RSAW Issued?	Comments
BAL-001-1	Real Power Balancing Control Performance	x	3/28/2014	New RSAW Posted
BAL-002-02	Contingency Reserve for Recovery from Balancing Contingency Event	Yes (Thru 3/16/15)	1/29/2015	Revised RSAWs Posted
BAL-003-1	Frequency Response and Bias Settings - redline of prior version	x	1/21/2015	Draft RSAW Posted
BAL-005-0.2b	Automatic Generation Control	x	5/20/2013	Revised RSAWs Posted
CIP-001-2a	Sabotage Reporting	x	10/13/2012	
CIP-002-5.1	Cyber Security - BES Cyber System Categorization	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-003-6	Cyber Security - Security Management Controls	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-004-6	Cyber Security - Personnel & Training	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-005-5	Cyber Security - Electronic Security Perimeter(s)	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-006-6	Cyber Security - Physical Security of BES Cyber Systems	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-007-6	Cyber Security - System Security Management	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-008-5	Cyber Security - Incident Reporting and Response Planning	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-009-6	Cyber Security - Security Management Controls	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-010-2	Cyber Security - Configuration Change Management and Vulnerability Assessments	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-011-2	Cyber Security - Information Protection	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-014-2	Physical Security	Yes (Thru 4/9/15)	2/20/2015	Draft RSAW Posted
COM-002-2a	Communication and Coordination	x	11/14/2012	
COM-002-4	Operating Personnel Communications Protocols	Yes (Thru 1/31/14)		
COM-003-1	Operating Personnel Communications Protocols	Yes (Thru 4/5/13)		
EOP-001-2.1b	Emergency Operations Planning	x	8/9/2013	Revised RSAWs Posted
EOP-002-3.1	Capacity and Energy Emergencies	x	3/20/2014	Revised RSAWs Posted
EOP-003-2	Load Shedding Plans	x	10/13/2012	
EOP-004-2	Event Reporting	N/A	10/15/2013	New RSAW
EOP-005-2	System Restoration from Blackstart Resources	x	7/17/2013	Revised RSAWs Posted
EOP-006-2	System Restoration Coordination	x	7/17/2013	Revised RSAWs Posted
EOP-008-1	Loss of Control Center Functionality	x	6/28/2013	Revised RSAWs Posted
EOP-011-1	Emergency Operations	Yes (Thru 9/25/14)	1-/20/2014	Draft RSAW Posted
FAC-001-2	Facility Interconnection Requirements	Yes (Thru 6/25/2014)		The draft RSAW is posted for feeback through June 25, 2014.
FAC-002-2	Facility Interconnection Studies	Yes (Thru 6/25/2014)		The draft RSAW is posted for feeback through June 25, 2014.
FAC-003-3	Transmission Vegetation Management	N/A	4/24/2014	Revision serves to clarify guidance for Requirement R6 regarding initial inspections for calendar year 2014 by expanding the Note to Auditor section
FAC-008-3	Facility Ratings	x	3/20/2014	Revised RSAWs Posted
FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	x	10/13/2012	
IRO-001-4	Reliability Coordination- Responsibilities	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-002-2	Reliability Coordination - Facilities	x	3/20/2014	
IRO-002-4	Reliability Coordination - Monitoring and Analysis	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-003-2	Reliability Coordination - Wide-Area View	x	3/20/2014	
IRO-005-3.1a	Reliability Coordination - Current-Day Operations	x	5/20/2013	Revised RSAWs Posted
IRO-008-2	Reliability Coordinator Operational Analyses and Real-time Assessments	Yes (Thru 12/22/2014)	11/5/2014	Revised RSAWs Posted
IRO-009-2	Reliability Coordinator Actions to Operate Within IROLs	Yes (Thru 7/8/2015)	3/16/2015	Draft RSAW Posted
IRO-010-2	Reliability Coordinator Data Specification and Collection	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	x	10/13/2012	

RSAW#	Title	Posted for Comment?	RSAW Issued?	Comments
IRO-014-3	Coordination Among Reliability Coordinators	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-017-1	Outage Coordination	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
MOD-028-2	Area Interchange Methodology	N/A	10/10/2013	New RSAW
MOD-031-1	Demand and Energy Data	Yes (Thru 11/22/13)		Draft RSAW posted along with Draft Standard
NUC-001-2		N/A	4/24/2014	Revised RSAW represent the initial release for the errata versions of the Reliability Standard
PER-001-0.2	Operating Personnel Responsibility and Authority	x	5/20/2013	Revised RSAWs Posted
PER-003-1	Operating Personnel Credentials	x	1/23/2013	
PER-005-1	System Personnel Training	N/A	10/15/2013	Revised RSAWs Posted
PRC-001-3	System Protection Coordination	Yes (Thru 5/15/15)	4/16/2015	Draft RSAW Posted
PRC-002-NPCC-01	Disturbance Monitoring	Yes (Thru 10/21/2014)	9/19/2014	Revised RSAWs Posted
PRC-004-2.1a	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	x	3/28/2014	Revised RSAWs Posted
PRC-004-3	Protection System Misoperation Identification and Correction	Yes (Thru 3/19/14)		Draft RSAW posted along with Draft Standard
PRC-004-5	Protection System Misoperation Identification and Correction	Yes (Thru 4/7/15)	2/20/2015	Draft RSAW Posted
PRC-005-1.1b	Transmission and Generation Protection System Maintenance and Testing	x	3/28/2014	Revised RSAWs Posted
PRC-005-2	Protection System Maintenance - Edits from Comments Received	x	10/14/2014	Draft RSAW Posted
PRC-006-2	Automatic Underfrequency Load Shedding	Yes (Thru 10/8/14)	9/10/2014	Revised RSAWs Posted
PRC-010-1	Undervoltage Load Shedding	Yes (Thru 8/7/2014)		
PRC-010-2	Undervoltage Load Shedding	Yes (Thru 4/7/15)	2/20/2015	Draft RSAW Posted
PRC-023-2	Transmission Relay Loadability	N/A	10/10/2013	Revised RSAWs Posted
PRC-025-1	Generator Relay Loadability	Yes (Thru 3/11/13)		
PRC-026-1	Relay Peformance During Stable Power Swings	Yes (Thru 12/2/2014)	11/12/2014	Draft RSAW Posted
PRC-027-1	Coordination of Protection System Performance During Faults	Yes (Thru 5/15/15)	4/16/2015	Draft RSAW Posted
TOP-001-1a	Reliability Responsibilities and Authorities	x	5/20/2013	Revised RSAWs Posted
TOP-001-3	Transmission Operations	Yes (Thru 1/7/2015)	12/3/2014	Revised RSAWs Posted
TOP-002-2.1b	Normal Operations Planning	x	3/20/2014	Revised RSAWs Posted

NPCC Regional Reliability Standards Executive Tracking Summary

Revised: 4/9/2015

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/UnderDev.aspx

Line No.	Regional Standard ID	Regional Reliability Standard Title	RSAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NPCC BOD Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	BPS-501-NPCC-01	Classification of Bulk Power System Elements (Withdrawn by RSC 8/07/09)	Yes (Thru 2/4/08)	NA	NA	NA	NA	NA	NA	NA	Withdrawn by RSC 8/07/09	Withdrawn
2	PRC-002-NPCC-01	Disturbance Monitoring	Yes (Thru 9/10/08)	Yes (Thru 10/24/09)	Yes (Thru 1/6/10)	Yes (1/6/10)	Yes (1/9/10)	Yes (11/4/10)	Yes (5/31/11)	Yes (10/20/11)	10/24/11 - Approved Standard posted publicly	Completed
3	PRC-006-NPCC-01	Automatic Underfrequency Load Shedding Program	Yes (Thru 8/25/08)	Yes (Thru 11/2/11)	Yes (Pre-ballot Thru 11/2/11)	Yes (11/18/11)	Yes (11/30/11)	Yes (2/9/12)	Yes (5/4/12)	Yes (2/21/13)		Completed
4	PRC-006-NPCC-02	Automatic Underfrequency Load Shedding										Under Development
5	PRC-002-NPCC-02	Disturbance Monitoring	Yes (Thru 2/23/2015)								Regional Standard Authorization Request (RSAR) has been submitted and approved Drafting Team Nomination period ended April 10, 2015	Under Development
6	PRC-002-NPCC-01, Interpretation R1.1		x	x	x	Yes (TFSP 10/19/12)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
7	PRC-002-NPCC-01, Interpretation R1.2.2		x	x	x	Yes (TFSP 4/8/13)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
7	PRC-002-NPCC-01, Interpretation R4, R5, and R6		x	x	x	Yes (TFSP 5/16/13)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
9	BAL-002-NPCC-01	Regional Reserve Sharing	Yes (Thru 11/2/10)	Yes (Thru 12/16/11)	Yes (Thru 1/6/10)						Nomination Form posted - nominations due by 11/10/11	Under Development
10	PRC-012-NPCC-01	Special Protection Systems	Yes (thru 8/18/08)									On Hold
11	Regional Standard Processes Manual	Regional Standard Processes Manual (RSPM)	N/A	Yes (Thru 10/20/13)	Yes (Thru 1/27/14)	Yes (1/27/14)	Yes (3/11/14)				NERC posted the proposed NPCC Regional Standard Processes Manual for a 45-day industry review through 8 p.m. Eastern on Wednesday, May 7, 2014	

x

Acronyms:

RSAR- Regional Standards Authorization Request
RRS- Regional Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOD- NPCC Board of Directors
BOT- NERC Board of Trustee

NPCC Document Open Process Executive Tracking Summary

Revised: 4/10/2015

Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

Line No.	Type	Document	Description	Latest Revision	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents	Mar-05		
2	Criteria	A-10	Classification of BPS Elements	Dec-09		
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria	Aug-07		
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13		
5	Guideline	B-12	Guidelines for On Line Computer System Performance During Disturbances	Nov-07		
6	Guideline	B-25	Guide to Time Synchronization Substation Equipment	Nov-08		
7	Guideline	B-26	Guide for Application of Disturbance Recording Equipement	Sep-06		
8	Guideline	B-27	Regional Critical Asset Identification Methodology	Feb-08		
9	Guideline	B-28	Guide for Generator Sequence of Events Monitoring	Feb-12		
10	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures	May-13		
11	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems	Jan-07		
12	Procedure	C-25	Procedure to Collect Power System Event Data	Sep-07		
13	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings	Mar-07		
14	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations	Dec-09		
15	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems	Apr-06		
16	Procedure	C-39	Procedure to Collect Major Disturbance Event Data	Dec-09		
17	Procedure	C-43	NPCC Operational Review for the Integration of New facilities	Aug-08		
18	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	Nov-14		

NPCC Directory Executive Tracking Summary

Revised: 6/18/2015 Further details regarding the individual documents may be found at:

Line No.	Document	Developed From	Title of Directory	Responsible Task Force	Latest Version	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	TFCP	Dec-09	CP11/CO7 Reviewing Phase 2 Draft	Directory#1 currently posted to the Open Process for a 3rd posting. Pending the resolution of further non substantive comments anticipate presenting Directory#1 and an implementation plan to the RCC in September. (Implementation Plan developed to install a 2nd line of high speed protection on certain facilities in New England).
2	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-09		
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	TFSP	Jun-09		Directory#3 retired effective April 1st, 2015 coinciding with nthe enforcement date of PRC -005-2.
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Dec-09	TFSP reviewing D#4 in accordance with NRAP review.	Directory#4 currently posted to the Open Process by TFSP for a 2nd posting.
5	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		
6	Directory #6		Regional Reserve Sharing		Apr-12		
7	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13		Task Force review underway to determine compliance implications for new defintion of RAS and revised PRC -012.
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10	TFCO working group CO11 reviewing initial Phase 2 draft of Directory #8.	TFCO Working Group CO11 reviewing Directory#8 to consider whether any of the battery testing in PRC -005-2 is dupicative with the battery testing in D8 for the Basic Minimum Power System.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		TFCO has considered an initial review of the criteria in D#9 and D#10 to insure that it is not inconsistent with MOD-25-2. TFCO agreed to establish a Working Group to consider this issue. (MOD-25-2 is enforceable on 7/1/2016).
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		
11	Directory #12		Under frequency Load Shedding Program Requirements	TFSS	Jul-13		
12	Directory Manual		Directory Development and Revision Manual	N/A	Dec-13		On October 6th, 2014 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the development of new or revised criteria as mandated by the NPCC BOD.

x

x

NPCC Directory Criteria Clarifications

Revised: **4/10/2015** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/Directory%20Interpretations/Forms/Public%20List.aspx

Line No.	Document	Title of Directory	Date Final	Task Force Review	Posted Open Process?	RCC Approval	Comments	Status
1	Directory #8 Interpretation	System Restoration	6/18/2012	TFCO	N/A	N/A	Interpretation on behalf of the NYSRC	Complete
2	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	8/28/2012	TFSP	N/A	N/A	Interpretation on behalf of Bangor Hydro	Complete
3	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	12/14/2012	TFSP	N/A	N/A	Interpretation on behalf of Con Ed	Complete
4	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	2/15/2013	TFSP	N/A	N/A	Response Clarified - Interpretation on behalf of Acumen Engineered Solutions	Complete
5	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	10/25/2013	TFSP	N/A	N/A	Interpretation on behalf of Hydro One Networks	Complete
6	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	3/4/2015	TFSP	Yes on October 16th, 2014.	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Interpretation	System Restoration	Pending	TFCO	Pending	Pending	Interpretation on behalf of OPG.	CO11 has rendered the interpretation which will be posted to the Open Process to receive comments.

x

Quarterly Application to the Nova Scotia Utility and Review Board (NSUARB) for Approval of NPCC Regional Reliability Criteria

Revised: **6/17/2015**

Line No.	Filing Period	Filing Due	Filing Submitted	Comments
1	October 1 to December 31, 2012	3/1/2013	3/1/2013	This filing is NPCC's initial quarterly filing covering the October 1 to December 31, 2012 period and covers the changes to the NPCC Criteria as a result of voting by the Full Members of NPCC.
2	January 1 to March 31, 2013	6/1/2013	N/A	No changes were made during the refeenced period which required filing.
3	April 1 to June 30, 2013	9/1/2013	N/A	No changes were made during the referenced period which required filing.
4	July 1 to September 30, 2013	12/1/2013	11/25/2013	Revisions to D#7 and D#12 approved by the Full Members on 7/9/2013.
5	October 1 to December 31, 2013	3/1/2014	N/A	No changes were made during the referenced period which required filing.
6	January 1 to March 31, 2014	6/1/2014	N/A	No changes were made during the referenced period which required filing.
7	April 1 to June 30, 2014	9/1/2014	N/A	No changes were made during the referenced period which required filing.
8	July 1 to September 30, 2014	12/1/2014	N/A	No changes were made during the referenced period which required filing.
9	October 1 to December 31, 2014	3/1/2015	2/23/2015	(1) 10/15/14 NPCC Full Members approved retirement of D#3 effective 4/01/15 coinciding with enforcement date of PRC -005-2.
10		3/1/2015	N/A	(2) 10/6/14 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the Manual.
11	January 1st to March 31st 2015	6/1/2015	N/A	No changes were made during the referenced period which required filing.
12	April 1st to June 30th 2015	9/1/2015	N/A	No changes were made during the referenced period which required filing.

Milestone Keys:

Tracking Spreadsheet: 2015 Project Work Plan (Status Updated: 3/

SP- SAR Posting
IB- Initial Ballot
AB - Additional Ballot
PB- Presented to BOT
F-Projected filing with FERC
PRP- Periodic Review Posting
PRR - Periodic Review Recommendation to SC

Project Status

No Issues with Project
Project Off Schedule by One Quarter
Project Off Schedule by Two or more Quarters
No Development Work in Progress

This worksheet displays estimates of anticipated standards development milestones for projects in 2015, and it is intended to be a project management tool for use in tracking the status of projects under development compared to their anticipated milestones. Detailed information for each project is available from their respective project pages on the NERC website. Projects that remained from 2014's Project Tracking Spreadsheet that were not prioritized in the RSDP, but that are continuing beyond the first quarter of 2015, are also represented here. Projects not anticipated to continue beyond the first quarter of 2015 are not included

Projected Posting Schedule

The above is a link to the schedule of upcoming postings, which is updated

Project Number	Activity/Project (Project Names Hyperlinked to Project Page)	Deliverable	Deadline, if any	Directionally consistent with IERP findings	Comments	PMOS Liaison	NERC Contact	Status: Green, Yellow, Red	Milestones: Planned vs. Actual/Projected (See Notes 3 and 4)	2015 JAN	2015 FEB	2015 MAR	2015 APR	2015 MAY	2015 JUN	2015 JUL	2015 AUG	2015 SEP	2015 OCT	2015 NOV	2015 DEC	2016 JAN	2016 FEB	2016 MAR	2016 APR	2016 MAY	2016 JUN	2016 JUL	2016 AUG	2016 SEP	2016 OCT	2016 NOV	2016 DEC
										First Quarter			Second Quarter			Third Quarter			Fourth Quarter			First Quarter			Second Quarter			Third Quarter			Fourth Quarter		
					The SPCSDT is continuing work on draft 5 of PRC-027-1. The SDT expects the standard to be posted for formal				2015 PMOS Plan			AB			AB		PB		F												
2007-06	System Protection Coordination	PRC-027			comment and ballot in April.	Jennifer Sterling	Al McMeekin	Project extended to address an additional issue by FERC	Actual/Projected				AB			AB				PB		F										
	Phase 2: System Protection	PRC-001-	NERC-						2015 PMOS Plan						IB		AB			PB		QQA2									
2007-06.2	Coordination	1.1., PRC-	imposed		Originally PRC-001-1.1.	Brenda Hampton	Scott Barfield		Actual/Projected						IB		AB			PB		F									
	Undervoltage Load Shedding for PRC-	PRC-004			A 45-day additional comment period and				2015 PMOS Plan			IB		PB		F															
2008-02.2	004	and PRC-			ballot are open until April 7.	Jennifer Sterling	Scott Barfield		Actual/Projected			IB		PB		F																
									2015 PMOS Plan					SP			IB		AB			AB					PB			F		
															SP																	
2009-02	Real-time Reliability Monitoring and Analysis Capabilities	New standard			Nominations close Friday, March 6.	Jennifer Sterling	Mark Olson	Phased to start after TOP/IRO Project 2014-03 completion	Actual/Projected								IB			AB					PB			F				
									2015 PMOS Plan				IB			AB			AB					PB			F				
					Project 2010-05.2 Phase 2 of Protection Systems was separated into two phases. In Phase 1, the SPSSDT developed a revised definition for the term Remedial Action Scheme (RAS) which was adopted by the NERC BOT in November 2014. Phase 2 will address the six SPS/RAS-related Reliability Standards. The standards will be consolidated and will address all aspects of SPS/RAS. The SDT began standards development in January and has meetings scheduled for February,																											
		Revised Definition of Remedial Action																														
2010-05.3	Phase 3 of Protection System Misoperations: RAS	Scheme			March, and April.	Colt Norrish	Al McMeekin		Actual/Projected						IB		AB			AB					PB			F				
	Phase 1 of Balancing Authority Reliability-based				A 45-day additional comment period and				2015 PMOS Plan		AB			PB		F															
2010-14.1	Controls: Reserves	BAL-002			ballot are open until March 16.	Ron Parsons	Darrel Richardson		Actual/Projected		AB				AB		PB		F												
					The SDT anticipates posting the first				2015 PMOS Plan		IB			PB		F															
		BAL-005 and BAL-			draft of the revised standards for industry comment in mid-April 2015.																											
2010-14.2.1	BAL-005 and BAL-006	006			Project delayed based on extent of changes required.	Ken Goldsmith	Darrel Richardson		Actual/Projected					IB			AB			PB		F										
									2015 PMOS Plan		PRP			PRP																	
					A 45-day additional ballot comment								SP																			
2010-14.2.2	BAL-004	BAL-004			period and ballot are open until March 16.	Ken Goldsmith	Darrel Richardson		Actual/Projected						IB		PB														
					at March SC meeting.				2015 PMOS Plan				PRP		PRP		PRR														
		IRO-006-East, IRO-			Initially identified as a periodic review. Revised to reflect implementation of								SP																		
2015-06	IRO Review	009			previous review.	Charles Yeung	Katherine Street		Actual/Projected						IB		AB			PB											
									2015 PMOS Plan	IB				PB		F															
2014-01	Dispersed Generation Resources	PRC-005			PRC-005-5 posted for final ballot until March 11.	Jennifer Sterling	Katherine Street		Actual/Projected	IB				PB		F															
					The drafting team met January 27-28 and made revisions to the standard to address the directive. The team will ask				2015 PMOS Plan			IB		PB		F															
2014-04	Physical Security Directives	CIP-014			for SC authorization to post for a 45-day	Brian Murphy	Steve Crutchfield		Actual/Projected			IB		PB		F															
									2015 PMOS Plan														SP		IB		AB		AB		PB	
2015-01	TPL Directive	TPL-001			This project has been put on hold indefinitely due to data collecting requirements.	Ron Parsons	Steve Crutchfield		Actual/Projected														SP		IB		AB		AB		PB	
		EOP-004, EOP-005, EOP-006, and EOP-							2015 PMOS Plan				PRP		PRP		PRR														
2015-02	Emergency Operations Periodic Review				Team was appointed by SC on Feb. 3 and project is in development.	Ken Goldsmith	Laura Anderson		Actual/Projected				PRP		PRP		PRR														
	Periodic Review of System Operating	FAC-010,			Team was appointed by SC on Feb. 3 and				2015 PMOS Plan					PRP			PRP		PRR												

2015-03	Limit Standards	FAC-011,			project is in development.	Brian Murphy	Mark Olson		Actual/Projected	PRP PRP PRR
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the Rules of	Glossary Terms			Team was appointed by SC on Feb. 3 and project is in development.	Andrew Gallo	Lacey Ourso		2015 PMOS Plan	SP IB AB PB F
									Actual/Projected	SP IB AB PB F
2007-17.4	PRC-005 Order No. 803 Directive.	PRC-005			The Standards Committee will be asked to authorize a posting for additional	Charles Yeung	Steve Crutchfield		2015 PMOS Plan	SP IB AB PB F
									Actual/Projected	SP IB AB PB F
2010-04.1	MOD-031 Order No. 804 Directives.	MOD-031					Darrel Richardson		2015 PMOS Plan	SP IB PB
									Actual/Projected	SP IB PB
2010-INT-03	Interpretation for TOP-002-2a R2, R8, and R19 for FMPP	TOP-002-2a					TBD		2015 PMOS Plan	
									Actual/Projected	
2012-INT-07	Interpretation for CIP-005 for AEP	CIP-005					TBD		2015 PMOS Plan	
									Actual/Projected	

Note 1: The prioritizations here reflect those prioritizations assigned as part of the 2015-2017 Reliability Standards Development Plan (RSDP). In its approach to prioritizing Reliability Standards projects, the RSDP considered how Reliability Standard family priorities are applied to individual projects and outstanding work. Specific elements included: (1) RISC Category Rankings; (2) regulatory directives; (3) regulatory deadlines; (4) Reliability Standard requirement candidates for retirement; (5) the IERP content and quality assessments; and (6) additional considerations (fill-in-the-blank status and five-year assessment commitments). Some projects were not prioritized in the RSDP, as they were originally anticipated to be

Note 2: Refers to guidances from regulatory orders for standards activity to consider, but that

Note 3: In the columns at right, in some cases, an "additional ballot" is not indicated for planning purposes, but if consensus is not supported on an initial ballot, or if substantive

Note 4: In the columns at right, there are no "plan" milestones in some cases because the project was originally planned to be complete in 2014, and the project's "actual" milestones

Note 5: In the column labeled "directionally consistent with IERP findings," directionally consistent indicates whether the Standard Drafting Team, when the project is completed, considered the recommendations from the Independent Expert Review Project and the Paragraph 81 project. After the Standard Drafting Team has considered the

IB				PB

		F

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Projected Posting Schedule

Below is a schedule of upcoming postings so you have the opportunity to schedule time with appropriate subject matter experts in your organizations to review these standards and ensure that balloters will be available during the ballot windows or have assigned proxies. The projected schedule is subject to change. For a high-level view of the planned schedule for all active projects, including information regarding the number of paragraph 81 requirements, directives, and guidances, please see the Project Tracking Spreadsheet on the Standards page.

Week of June 1:

- None

Week of June 8: **(Pending SC authorization June 10)*

- 2007-17.4 PRC-005 FERC Order No. 803 Directive Revised Informal posting (30-day informal comment period)*
  - Posting includes – revised SAR, redlined Standard, and implementation plan
- 2014-01 Standards Applicability for Dispersed Generation Resources White Paper (30-day comment period*)*
- 2015-04 Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedures (Appendix 2 of the Rules of Procedure) (45-day comment period and Initial Ballot)*
- 2015-07 COM-001 FERC Order No. 808 Directive (14-day nomination solicitation)*
- 2015-07 COM-001 FERC Order No. 808 Directive Standard Authorization Request (SAR) (30-day comment period)*

Weeks of June 15: **(Pending SC authorization June 10)*

- 2015-08 PRC-006-3 Automatic Underfrequency Load Shedding – Variance for the Quebec Interconnection (14-day nomination solicitation)*
- 2015-08 PRC-006-3 Automatic Underfrequency Load Shedding – Variance for the Quebec Interconnection Standard Authorization Request (SAR) (30-day comment period)*

Weeks of June 22:

- None

Weeks of June 29:

- None

Week of July 6:

- None

**Please note that the dates in the chart below are estimates and are subject to change.

Projects	5/25	6/1	6/8	6/15	6/22	6/29	Closing Date
2007-06 System Protection Coordination PRC-027							
2007-06.2 Phase 2 of System Protection Coordination PRC-001							
2007-17.4 PRC-005 Order No. 803 Directive – SAR			6/11				7/10
2008-02.2 Phase 2 of UVLS: Misoperations PRC-004, PRC-010							
2009-02 Real-time Reliability Monitoring & Analysis Capabilities							
2010-04.1 MOD-031 FERC Order No. 804 Directives Standard							
2010-05.3 Phase 3 of Protection Systems: RAS							
2010-07.1 FAC 003 Vegetation Management							
2010-14.1 Phase 1 of BARC BAL-002							
2010-14.2.1 Phase 2 of BARC BAL-005							
2010-14.2.1 Phase 2 of BARC BAL-006							
2010-14.2.2 Phase 2 of BARC BAL-004 Supplemental Nomination Solicitation	5/21	6/1					
2014-01 Standards Applicability for Dispersed Generation Resources White Paper			6/12				7/13
2014-04 Physical Security Directives CIP-014							
2015-02 Periodic Review of Emergency Operations							
2015-03 Periodic Review of System Operating Limit Standards FAC-010				6/18			
2015-03 Periodic Review of System Operating Limit Standards FAC-011				6/18			
2015-03 Periodic Review of System Operating Limit Standards FAC-014				6/18			
2015-04 Alignment of NERC Glossary of Terms & Definitions Used in the Rules of Procedures (Appendix 2 of the Rules of Procedures)			6/12				7/31
2015-06 Interconnection Reliability Operations and Coordination – IRO-006-EAST, IRO-009							7/8
2015-06 Interconnection Reliability Operations and Coordination – IRO-006-EAST, IRO-009							7/8
2015-07 COM-001 FERC Order No. 808 Directive Nomination Solicitation			6/11		6/24		
2015-07 COM-001 FERC Order No. 808 Directive SAR			6/11				7/15
2015-08 PRC-006-3 Automatic Underfrequency Load Shedding – Variance for the Quebec Nomination Solicitation				6/15		6/29	
2015-08 PRC-006-3 Automatic Underfrequency Load Shedding – Variance for the Quebec SAR				6/15			7/17
Number of Standards Posted	5	5	9	10	7	7	

	Nomination solicitation
	21-day comment period
	30-day comment period
	45-day comment period and ballot/additional ballot
	45-day comment period
	Final ballot

RSC Meeting #14-3, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Ongoing Guy Zito provided updates on the RSAWs. CC will review RSAWs going forward.
4.2	Lee Pedowicz needs to come up with a way to identify the group names in the Balloting and Commenting System	Lee Pedowicz	RSC Meeting	
4.3	NPCC Standards Staff will review the SAR for a Quebec Variance to continent-wide PRC-006-2 Automatic Underfrequency Load Shedding and finalize it. NPCC will then transmit the SAR to NERC and be a joint "requester".	NPCC Standards Staff	RSC Meeting	Completed SAR is submitted on May 6th, 2015.
4.4	Contact Alan McNaughton for an additional personnel on the RSC Roster for Sector 2	RuiDa Shu	RSC Meeting	Completed Randy MacDonald is added to the RSC Roster on May 19th, 2015.

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Weekly Standards & Compliance Bulletin

June 1–7, 2015

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2015-06 – Interconnection Reliability Operations and Coordination – IRO-006-EAST-2, IRO-009-2	Initial Ballot in the SBS	06/29/15	07/08/15

Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2015-06 – Interconnection Reliability Operations and Coordination – IRO-006-EAST-2, IRO-009-2	Join Ballot Pools in the SBS	05/21/15	06/19/15

Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2015-03 – Periodic Review of System Operating Limit Standards – FAC-010, FAC-011, FAC-014	Comment Form in SBS	05/04/15	06/17/15
Project 2015-06 – Interconnection Reliability Operations and Coordination – IRO-006-EAST-2, IRO-009-2	Comment Form in SBS	05/21/15	07/08/15

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
CIP V5 Transition Program FAQs Posted: NERC has posted a new group of FAQs to the CIP V5 Transition Program web page for industry comment. NERC will review all comments provided and incorporate changes before issuing a final version of the May 1, 2015 FAQs.	Type comments directly into the draft FAQ document as instructed in the document and submit the feedback to TransitionProgram@nerc.net.	05/01/15	06/15/15
First Draft of 2016 Business Plans and Budgets Posted for Review and Comment: NERC has posted the first drafts of its 2016 Business Plan and Budget and the Regional Entities' 2016 Business Plans and Budgets for review and comment. NERC has also posted a cover letter from Senior Vice President and Chief Financial and Administrative Officer Mike Walker and a PowerPoint presentation providing a summary and overview of the consolidated posting.	Submit comments to anya.josephson@nerc.net.	05/19/15	06/30/15

GENERAL STANDARDS NEWS

NEW Updated Archived Reliability Standards Under Development Web Page

NERC has updated the Archived Reliability Standards Under Development web page to include the projects listed in the Standard and Project Cross References guide located on the left navigation pane of the Standards web page. The Archived Reliaiblity Standards Under Development page provides a quick reference for closed projects. NERC updates it each time the NERC Board of Trustees adopts a new standard(s).

QUICK LINKS

Register in the SBS
Original Balloting Software
Projected Standards Posting Schedule
Project Tracking Spreadsheet
Standards Related Questions – Single Portal
2015–2017 Reliability Standards Development Plan

Solicitation Period Open for Supplemental Drafting Team Nominations for Project 2010-14.2.2 – Phase 2 of BARC: Time Error Correction

NERC is seeking nominations for the Project 2010-14.2.2 – Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction standard drafting team through 8 p.m. Eastern on June 1, 2015. Previous drafting or review team experience is beneficial but not required. A

brief description of the desired qualifications and expected commitment, along with Word and electronic versions of the nomination form, are available on the Standard Drafting Team Vacancies web page.

This is a supplemental solicitation to the initial solicitation held in March. At its May 20, 2015 meeting, the Standards Committee approved the nominations of the recommended nominees from the initial solicitation and requested that a supplemental nomination period be opened to garner additional team members. If you submitted a nomination form during the initial solicitation, please do not resubmit your nomination form, as you have already been selected for the drafting team.

New Resource for VRF and VSL Information

The former Violation Risk Factor and Violation Severity Level matrices were replaced by a single combined VRF and VSL report. The new Excel report includes categories for VRF, VSL, Jurisdiction, and Requirement. Each column is sortable with a separate worksheet for each category that provides additional information. The report will be updated each time a standard's VRF or VSL status changes, and a "Last Updated Date" column will indicate recent changes.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW Upcoming Small Group Advisory Sessions

Continuing the series of advisory sessions that began earlier this year, the ERO is hosting three additional Small Group Advisory Sessions to provide helpful information to registered entities that are implementing the CIP Version 5 Reliability Standards:

- July 8–10, 2015 at Texas RE in Austin
- August 4–6, 2015 at NERC HQ in Atlanta
- September 1–3, 2015 at NERC HQ in Atlanta

QUICK LINKS

Risk-Based CMEP (RAI Page)
CIP V5 Transition Program
Risk-Based Registration Initiative
Reliability Standard Audit Worksheets
Enforcement & Mitigation: Enforcement Actions
Navigating Enforcement Data: Webinar & Presentation

Each session will be a closed one- to two-hour discussion between a registered entity's subject matter experts and ERO staff on issues pertinent to the entity's implementation of CIP V5. There is no limit to the number of entity subject matter experts who can participate, and NERC can arrange remote participation for those not attending in person.

NERC will schedule specific sessions and notify entities of their appointment times after reviewing the registration requests, which will be accepted on a first-come, first-served basis. If the number of requests exceeds the time allotted, NERC will make alternative arrangements for the affected entities.

NERC will not host a CIP V5 workshop in conjunction with these events; however, recordings of past workshops and other CIP V5 information is available in the Curriculum document on the CIP V5 Transition Program web page.

Registration links and other detailed event information for the Small Group Advisory Sessions are available below, under "Upcoming Events."

NEW Resources Posted for Latest Risk Elements Webinar

The slide presentation and recording from the Risk Elements Webinar Series: Monitoring and Situational Awareness on May 21, 2015 have been posted. Registration information for other upcoming webinars in the Risk Elements Webinar Series is available below, under "Upcoming Events."

OTHER NEWS

NEW State of Reliability Report Released

NERC completed an independent review of bulk power system trends to analyze the state of reliability and provide an integrated view of reliability performance in its annual *State of Reliability 2015*. The report's key findings show the bulk power system sustained high reliability performance, realized a reduction in unplanned transmission outages leading to load loss, maintained stable frequency response, and experienced no instances of load loss due to a cyber or physical security risk. Consistent with prior *State of Reliability* report findings, uncontrollable severe weather events continue to be the largest factor affecting the performance of the bulk power system.

The *State of Reliability 2015* report's findings and recommendations serve as input to NERC's risk assessment and reliability standards project prioritization of specific actions that can be taken to manage potential risks and enhance bulk power system reliability.

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

The following standards are subject to future enforcement. Please refer to the U.S. Enforcement Dates page for more detail:

U.S. Enforcement Date	Standard(s)
July 1, 2015	MOD-032-1 – Data for Power System Modeling and Analysis; PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding
October 1, 2015	CIP-014-1 – Physical Security; PRC-006-2 – Automatic Underfrequency Load Shedding; COM-001-2 – Communications
January 1, 2016	FAC-001-2 – Facility Interconnection Requirements; FAC-002-2 – Facility Interconnection Studies; NUC-001-3 – Nuclear Plant Interface Coordination
April 1, 2016	CIP-002-5.1 – Cyber Security – BES Cyber System Categorization; CIP-003-5 – Cyber Security – Security Management Controls; CIP-004-5.1 – Cyber Security – Personnel & Training; CIP-005-5 – Cyber Security – Electronic Security Perimeter(s); CIP-006-5 – Cyber Security – Physical Security of BES Cyber Systems; CIP-007-5 – Cyber Security – System Security Management; CIP-008-5 – Cyber Security – Incident Reporting and Response Planning; CIP-009-5 – Cyber Security – Recovery Plans for BES Cyber Systems; CIP-10-1 – Cyber Security – Configuration Change Management and Vulnerability Assessments; CIP-011-1 – Cyber Security – Information Protection; PRC-005-3 – Protection System and Automatic Reclosing Maintenance
July 1, 2016	BAL-001-2 – Real Power Balancing Control Performance; COM-002-4 – Operating Personnel Communications Protocols; MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; MOD-031-1 – Demand and Energy Data; PER-005-2 – Operations Personnel Training; PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection; PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings
July 1, 2017	MOD-033-1 – Steady-State and Dynamic System Model Validation

BOARD OF TRUSTEES AND FERC ACTION

There is no Board of Trustees or FERC action to report from last week.

UPCOMING EVENTS

For information about other NERC events, such as meetings and conference calls for standard drafting teams, other standing committees, subcommittees, task forces, and working groups, please refer to the NERC calendar.

Workshops and Conferences

- Project 2009-02 – Real-time Monitoring and Analysis Capabilities SAR Technical Conference – June 4, 2015, Atlanta | Agenda | Register to Attend in Person | Register to Attend via Webinar
- CIP Version 5 Small Group Advisory Sessions – July 8–10, 2015, Austin | Register by June 26| Texas RE Office Information
- CIP Version 5 Small Group Advisory Sessions – August 4–6, 2015, Atlanta | Register by July 24| NERC HQ Office Fact Sheet
- CIP Version 5 Small Group Advisory Sessions – September 1–3, 2015, Atlanta| Register by August 21| NERC HQ Office Fact Sheet

Webinars

- Risk Elements Monthly Webinar Series: Infrastructure Maintenance – 1:00–2:00 p.m. Eastern, June 18, 2015 | Register
- Risk Elements Monthly Webinar Series: Protection System Misoperations – 1:00–2:00 p.m. Eastern, July 16, 2015| Register
- Risk Elements Monthly Webinar Series: Workforce Capability – 1:00–2:00 p.m. Eastern, August 20, 2015| Register

Standing Committee Meetings and Conference Calls

- Standards Committee Conference Call – 9:00 a.m.–2:00 p.m. Eastern, June 10, 2015 | Register
- Compliance and Certification Committee Meeting – June 10–11, 2015, Arlington, VA | Register

ABOUT THE WEEKLY STANDARDS & COMPLIANCE BULLETIN

This weekly bulletin compiles a list of standards and compliance projects with actionable deadlines, as well as upcoming events, recently posted resources, other NERC documents posted for comment, and other relevant news and information. Please email Mallory Huggins with feedback on this bulletin. The current bulletin and old bulletins are available under "Program News" on both the Standards home page and the Compliance & Enforcement home page.

If you would like to receive this bulletin or be added to the distribution list for a particular standards project, please email Arielle Cunningham. For more information about any of the compliance news listed in the bulletin, please contact Brooke Thornton.

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PRC-006-3--Automatic Underfrequency Load Shedding – Variance for the Quebec Interconnection		
Date Submitted:	May 6, 2015		
SAR Requester Information			
Name:	Patrick Doyle Lee R. Pedowicz		
Organization:	Hydro-Québec TransÉnergie Northeast Power Coordinating Council, Inc. (NPCC)		
Telephone:	1-514-879-4100 ext 5429 1-212-840-1070	Email:	doyle.patrick@hydro.qc.ca lpedowicz@npcc.org
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to Existing Standard		☐ Withdrawal of Existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry need for this SAR is to address two specific problems regarding UFLS requirements for the Quebec Interconnection : 1 - To meet the PRC-006-2 59.3 Hz requirement for scenarios where Quebec has a small generation

SAR Information
deficiency (between 4 and 6 percent) those scenarios would require modifications to the current settings of the UFLS program to the threshold of 59.3 Hz which would cause unacceptable and frequent load shedding without any improvement to System reliability. 2 – Because the Quebec Interconnection itself is an island with unique generation characteristics and SPS applications, Section D.A.3 in PRC-006-2 needs to be revised to define a more accurate generation deficiency scenario applicable to the Quebec Interconnection.
Purpose or Goal (How does this request propose to address the problem described above?):
The purpose of this SAR is to address the two problems mentioned above by modifying only those sections that are specific to the Quebec Interconnection (PRC-006-2 Section D. Regional Variances, Part D.A. Regional Variance for the Quebec Interconnection, and Attachment 1A (Quebec)). Revisions to the standard will ensure the continuity of System reliability in the Quebec Interconnection.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The modifications proposed in this SAR will not change the original goals and objectives of PRC-006-2 and will only affect the Quebec Interconnection.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
A description of the two specific problems is as follows: 1 - The Quebec Interconnection has a low inertia compared to other Interconnections. This makes it subject to large frequency deviations during normal operation. Small generation deficiencies (4 to 6 percent) can lead to acceptable frequency deviations without triggering any UFLS thresholds, but still stabilize under a PRC-006-2 Attachment 1A performance curve. The scope of this SAR is to modify the performance curve in Attachment 1A to better reflect the design, performance, and modeling of the Quebec Interconnection and avoid unnecessary load shedding. 2 - The Quebec Interconnection is an island by itself and is the only island considered when performing the Quebec UFLS program assessment. No under-generated island can be created within the Quebec Interconnection. Under current planning and operational criteria, the largest generation deficiency scenarios are limited to the loss of the largest power plant not covered by a SPS. Using the peak case scenario, these generation deficiencies are far from the required 25%. Section D.A.3 should be revised to account for the characteristics of the Quebec Interconnection.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
1 - Because of the characteristics of the Quebec Interconnection, 0.5-1.5 Hz frequency deviations resulting from small losses of generation occur frequently. The System is designed and operated such that these small generation losses are acceptable, do not pose any threat to System reliability, and do not lead to unnecessary automatic load shedding. The adjustment of the UFLS anti-stall threshold to meet the PRC-006-2 performance curve would cause frequent and unacceptable load shedding operations without any improvement to System reliability. This is clearly shown by recent UFLS program assessment studies, planning and operational studies, and the analysis of generation loss scenarios in the Quebec Interconnection. During the 2014 assessment of the NPCC Underfrequency Load Shedding Program, studies showed that for small generation deficiencies (between 4 and 6 percent) in the Quebec Interconnection using the minimum spinning reserve requirement, the simulated frequency deviation does not meet the PRC-006-2 requirement of 59.3 Hz from Attachment 1A. However, further investigation determined that such scenarios result in acceptable frequency deviations without crossing any UFLS thresholds while stabilizing between the PRC-006-2 curve (59.3 Hz in Attachment 1A) and the upper UFLS (anti-stall) threshold (59.0 Hz) that is defined in PRC-006-NPCC-1 UFLS Table 4 - Quebec Interconnection. Meeting the PRC-006-2 59.3 Hz requirement for those scenarios would require modifications to the current settings of the UFLS program. The subsequent adjustment of the UFLS anti-stall threshold to 59.3 Hz would cause unacceptable and frequent load shedding without any gain to System reliability. 2 - The Quebec Interconnection is an island by itself and it is the only island considered when performing the Quebec UFLS program assessment. Due to the nature of the Quebec System's design (main generation centers located in the north, remote from the main load centers in the south), no other viable island with generating deficiencies can be created within the Quebec Interconnection. Under current planning and operational criteria, the largest generation deficiency scenarios are limited to the loss of the largest power plant not covered by a SPS. Assuming the Hydro-Quebec peak case scenarios, none of them would result in a 25% generation deficiency. To reach the 25 % criteria using a design (normal or extreme) contingency and viable island, a light load scenario was used while studying the loss of the largest power plant. This methodology is currently used in Hydro-Quebec and has been

SAR Information
used since the JWG-2 Phase II (NPCC Joint Working Group for the review of adequacy of procedures for protection against off-nominal frequency operation) Report was published in 1993. However, further studies and investigations have shown that using the peak case scenario, the integrity of the Quebec Interconnection could not be preserved using a UFLS program for a 25% generation deficiency. Since there is no design contingency that can produce a generation deficiency of 25%, multiple extreme contingencies, such as the loss of more than one substation, need to be applied simultaneously on the peak case scenario in order to reach that level of generation deficiency. Using the peak load case scenario, these generation deficiencies do not meet the required 25%. Section D.A.3 should be revised to reflect the characteristics of the Quebec Interconnection.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).

Reliability Functions		
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the end-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	Quebec
RFC	None
SERC	None
SPP	None
WECC	WECC

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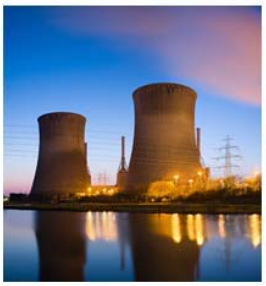
Integration of Variable Generation Task Force

Summary and Recommendations of 12 Tasks

DRAFT

June 2015

RELIABILITY | ACCOUNTABILITY



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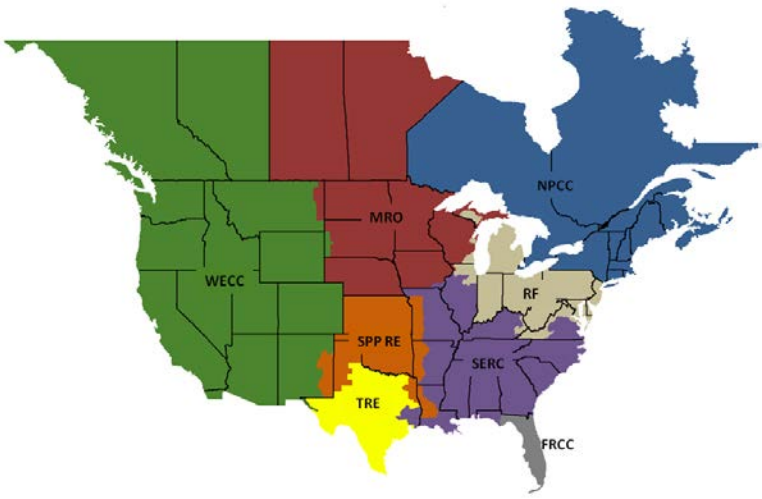
Preface

This document is a work in progress. The executive summary, annexes, definitions of terms, abbreviations, and rosters may be modified prior to final publication. The final report will also include the incorporation of additional formatting, as well as other checks on abbreviation, references in footnotes, grammar, etc. All figures will also be properly cleaned and formatted for clarity, based on the mock-ups included in this draft. Figures and tables have not yet been numbered or referenced in the text. The data and conclusions in this document are subject to change until the report is finalized and submitted to the NERC Planning Committee (PC) for approval.

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

This report summarizes the 12 tasks performed by the Integration of Variable Generation Task Force (IVGTF). The IVGTF's objective is to evaluate the effects of large-scale integration of variable generation (VG) and identify the long-term reliability considerations needed to ensure the reliability of the BPS. The findings and recommendations from the multi-task effort provide a reference of best practices and considerations for planners, operators, and regulators, with recommendations identifying areas that require further development. Areas of improvement are suggested for technical considerations, additions to regional requirements or guidelines, and Standards Authorization Requests (SARs) for new or enhanced Reliability Standards.

NERC's *2013 Long-Term Reliability Assessment* noted that renewable capacity (including wind, solar, hydro, biomass, and geothermal) will grow by approximately 55 GW by 2023. With over 35 GW of planned nameplate capacity, wind accounts for over half (64 percent) of these additions.[1] Anticipating substantial growth of VG, NERC's Planning Committee (PC) and Operating Committee (OC) created the IVGTF that first prepared the 2009 overview report entitled *Accommodating High Levels of Variable Generation*.[2] In addition to defining various technical considerations for integrating high levels of VG, the IVGTF report identified a work plan of follow-on tasks to investigate potential mitigating actions, practices, and requirements needed to ensure BPS reliability. The 12 reports that are summarized herein represent the results of the follow-on tasks that were identified in the initial 2009 report.

The purpose of this report is to document all recommendations from the task force and determine the status of these recommendations by identifying next steps for NERC. While this is an ongoing process, the task force members recognize that various recommendations have already been addressed by standard drafting teams, other task forces or working groups, and in NERC's special reliability assessment reports since the reports were published. Therefore, IVGTF leadership, in collaboration with NERC's System Analysis and Data Modeling group and selected NERC standard drafting teams, and members from Essential Reliability Services Task Force (ERSTF) has reviewed the recommendations from all the reports to determine the appropriate actions. Appendix I contains an *IVGTF Transition Plan* that identifies the next steps for the IVGTF recommendations, including recommendations that are still relevant for possible revisions to standards, additions to technical guidelines, suggestions for further research, or recommendations for operating and planning best practices.

[1] NERC, *Long-Term Reliability Assessment*, December 2013 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.

[2] NERC, *Special Report - Accommodating High Levels of Variable Generation*, http://www.nerc.com/files/IVGTF_Report_041609.pdf, April 2009.

Background and Recommendations Summary

North America is facing a significant growth in VG resources over the coming 10 years, making it necessary to reliably integrate these resources into the grid. Continued integration of VG was identified among long-term reliability challenges in the *2013 Long-Term Reliability Assessment,* where nameplate renewable capacity (including wind, solar, hydro, biomass, and geothermal) is projected to grow by approximately 55 GW by 2023. With over 35 GW of planned nameplate capacity, wind accounts for 64 percent of these additions. Driven in large part by new policies and environmental priorities, this growth will create one of the largest resource integration efforts in the history of the electric industry.

In addition to defining various technical considerations for integrating high levels of VG, the PC and OC's IVGTF report identified a work plan of follow-on tasks to investigate potential mitigating actions, practices, and requirements needed to ensure BPS reliability. Table 1 illustrates all IVGTF objectives and their associated special assessment reports prepared by different drafting teams.

Table 1: IVGTF Task Force Topics and Objectives

IVGTF	Objective(s)	Special Assessment
Task 1-1	Identify the need for Modeling, Data and Analysis (MOD) standards.	Standard Models for Variable Generation May, 2010
	Determine valid, generic, non-confidential, and public power flow and stability models for VG technologies.	
	Review existing NERC MOD standards.	
Task 1-2	Address consistent and accurate methods to calculate capacity values attributable to VG.	Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning March, 2011
Task 1-3	Make recommendations for how NERC interconnection procedures and standards should be enhanced to address: • Voltage and frequency ride-through • Reactive and real power control • Frequency and inertial response criteria	Interconnection Requirements for Variable Generation September, 2012
Task 1-4	Develop the planning and operational practices as well as the methods and resources needed to integrate VG resources into the BPS.	Flexibility Requirements and Metrics for Variable Generation: Implications for Planning Studies August, 2010
Task 1-5	Identify the need to assess reliability implications of integrating:	Potential Reliability Impacts of Emerging Flexible Resources

	• Plug-in hybrid electric vehicles • Storage Devices • Demand Response (DR) programs	November, 2010
Task 1-6	Summarize the potential influence on power system operating and planning decision problems of VG increased uncertainty.	Probabilistic Methods July, 2014
	Describe the role that probabilistic methods can play in improving the basis on which the various decisions are made.	
Task 1-7	Discuss potential requirements for Variable Energy Resources (VERs) connected to distribution facilities, and the potential BPS reliability impacts if VERs do not remain interconnected, stable, and operational during and after normally expected momentary system disturbances in the BES, and offer general guidelines of Voltage Ride Through (VRT) and Frequency Ride Through (FRT) specifications for distributed VERs for consideration in the IEEE 1547 Standard revision.	Performance of Distributed Energy Resources During and After System Disturbance Voltage and Frequency Ride-Through Requirements December, 2013
Task 1-8	Identify the potential impacts of Distributed Energy Resources (DERs).	Potential Bulk System Reliability Impacts of Distributed Resources August, 2011
	Identify potential mitigating strategies.	
	Review existing NERC Registry Criteria specific to DER applications.	
	Propose potential future approaches to ensure continued reliability in systems with large amounts of DERs.	
Task 2-1	Discuss the forecasting requirements for the 48 hours of operation ahead and how forecasting information can be delivered to the system operator in a useful and actionable way.	Variable Generation Power Forecasting for Operations May, 2010
Task 2-2	Address communications requirements between the variable renewable generation plant and the Balancing Authority (BA).	Reliability Considerations for BA Communications with Increased Variable Generation March, 2012
Task 2-3	Assess the need for and requisite participation in the acquisition of ancillary services.	

	Study provisions of ancillary services from other jurisdictions, ACE sharing, or shorter scheduling intervals within and between BA Areas to manage and spread the effects from variability of generation resources over a larger footprint.	Ancillary Services and Balancing Authority Area Solutions to Integrating Variable Generation March, 2011
	Review existing and proposed standards.	
Task 2-4	Discuss VG impact on power system operations.	Operating Practices, Procedures and Tools March, 2011
	Discuss the need to modify operating practices, procedures, and tools.	
	Address the impacts on commitment and/or dispatch along with reserve management practices.	

Main Recommendations and Key Findings

This report summarizes one of the most important issues facing the reliability of the BPS today—the large-scale integration of VG. In light of the increasing long-term VG trend and as a result of the accomplishments of the 12 IVGTF task reports, addressing the effects of VG on the reliability of the BPS will require significant changes to traditional methods used for system planning and operation. The reports represent broad industry consensus and a pioneering IVGTF effort to lay the foundation for the reliable integration of VG into the BPS. This summary report highlights areas of recommendations where further study, enhanced practices, modifications to existing standards, suggestions for consideration of new standards, and ongoing coordination with the industry are needed to ensure reliability as more VG resources are added to the grid.

Findings and recommendations from the IVGTF multi-task effort provide a reference manual of best practices for planners, operators, regulators, developers, and investors dealing with the challenges and opportunities offered by VG. Therefore, this summary report identifies recommendations into the following categories:

- Modeling, Data and Analysis (MOD) Standards Development and Reconciliation
- VG for Resource Adequacy In Operation and Planning
- Interconnection Requirements
- Flexibility Requirements
- Reactive Power and Voltage Control Requirements
- Active Power Control Capabilities
- Disturbance Requirements
- Communications Requirements
- Harmonics and Subsynchronous Interaction
- VG Power Forecasting
- Ancillary Services Requirements

The report also provides a status update through a constructive transition plan for all recommendations from all 12 of the task reports according to appropriate next phases of considerations and actions. Table 2 highlights the main recommendations and their associated transition categories, which fall into the following categories:

- Standards Review and/or Standard Authorization Request (SAR)
- Enhancements to Modeling
- Definition – Revisions or Addition by NERC
- Operating – Technical Guidelines
- Planning – Technical Guidelines
- Research and Development
- NERC Training and Education
- NERC Reliability Assessments
- Operators Training and Data Collection
- Essential Reliability Services Task Force (ERSTF)
- NERC Staff/External Coordination Activity
- No Action:
  - No Action – Recommendation is out of scope.
  - No Action – Recommendation is not applicable (e.g., due to market or commercial action improvements).
  - No Action – Recommendation is completed or has been addressed by different projects.

The most important recommendations are those that target a gap or enhancements needed to NERC Reliability Standards. The IVGTF has highlighted three key areas that should be addressed by a new NERC Reliability Standard or enhancement of an existing Reliability Standard. Those are:

- **Interconnection Requirements**
  - FAC-001 needs to be clarified to state that interconnection standards for reactive power must cover specifications for minimum static and dynamic reactive power requirements at full power and at partial power. The requirement should include how terminal voltage affects the power factor or reactive range requirement.
  - Consider modifying VAR-001 to include the term “plant-level volt/var controller” (in addition to “AVR”), which is more appropriate for VG.
- **Reactive Power and Voltage Control Requirements**
  - Create a clear definition of acceptable control performance for minimum reactive power capability requirements for interconnection of all generators.
  - Add applicability recommendations for generator interconnection requirement for reactive power
  - Include specification of reactive range defined over the full output range and applicable at the point of connection
  - Specify expected reactive control performance, including minimum control response time for voltage control, power factor control, and reactive power control.
- **Active Power Control Capabilities**
  - NERC should investigate variable generating plants at an active power level where dynamic reactive capability is limited or zero.

- NERC should specify active power requirement during a voltage disturbance unless there is a reliability concern (review of PRC-024 standards and clarity on repeated disturbances).
- NERC should include active power curtailment capabilities of various types of generation as one of the possible remedies available to Balancing Authorities (review EOP-002 and add clarity on Control Performance and Disturbance Control Standards).

- **Variable Generation Forecasting Requirements**
  - Add forecastingMOD information available for VG for next-day system studies (review IRO-004 Reliability Coordination – Current-Day Operations and add VG forecasting information to provide an accurate day-ahead study).
  - Include active monitoring of forecasting conditions such as weather fronts, icing, and high-wind conditions by the Reliability Coordinator (review IRO-005 Reliability Coordination – Current-Day Operations).
  - Include a section about forecasting, identifying the data submitted by variable generators as the method of providing generation information to the Transmission Operators, and also recognizing forecasting as the best way to estimate generation, albeit subject to some unavoidable uncertainty due to the variability and complexity of weather conditions. This would assist in system operations, especially in day-ahead or hour-ahead operations (review TOP-006 Normal Operations Planning).
  - Include specific tools, such as (1) input from a forecaster, and (2) real-time data from wind and solar plants (e.g., meteorological towers, sonic detection and ranging (SODAR) and real-time turbine telemetry) (review TOP-006 Monitoring System Conditions).
  - NERC Reliability Standards that address the reasonable and effective use of regional forecasts and local wind/solar facility forecasts should be encouraged and used to schedule VG to assist in accurate system operation. Wind plant output forecasts, often several of them, should be adopted as standard system and market operation tools for economic operation and system reliability purposes. Ramp forecasts and hourly energy forecasts should be considered.

More details, including the specific transition category for each IVGTF recommendation, can be found in Appendix I of this report.

Lastly, the Conclusions and Recommendations section of this report provides a perspective on the significance of the work in the context of ongoing system evolution.

Table 2: Main Recommendation Topics Covered by Task Forces' Work Plan Activities

Recommendation Category	Recommendations	Transition Category
MOD Standards Development and Reconciliation	Provide sufficient clarity to model VG.	Enhancements to Modeling
	Support simulation of power system with high amounts of VG aiming to incorporate VG considerations in the next release of the MOD standards.	No Action – Completed

VG for Resource Adequacy in Operation and Planning	Resource adequacy models (e.g., LOLP models) that reflect the much lower availability or lower load-carrying capability of VG.	Planning – Technical Guidelines
	Measure VG performance factors such as capacity factors and peak coincidence.	Research & Development
	Apply more research using probabilistic methods for reserve calculations, dispatch, unit commitment, maintenance, generation, and transmission planning.	Research & Development
Interconnection Requirements	Consider adding a clarification to FAC-001 expanding R.2.1.3 or as an appendix, stating that interconnection standards for reactive power must cover specifications for minimum static and dynamic reactive power requirements at full power and at partial power. Include how terminal voltage should affect the power factor or reactive range requirement (see Section 2.8.3 for technical guidelines).	Standards Review and/or SAR
	Consider modifying VAR-001 to include the term "plant-level volt/var controller" (in addition to "AVR"), which is more appropriate for VG.	Standards Review and/or SAR
	Enhance models for facility interconnections studies—consideration for MOD 24 to MOD 27 enhancements.	No Action – Completed
	Detailed dynamic (and possibly transient) models for the specific equipment may be needed for the System Impact Study and Facilities Study to represent the facility and other equipment in the electrical vicinity.	Enhancements to Modeling
	Support simulation of power system with high amounts of VG.	Planning – Technical Guidelines
	Review DER interconnection standards.	No Action – Completed[3]
	Investigate interconnections for breaker requirements.	Planning – Technical Guidelines
Flexibility Requirements	Probabilistic planning methods being developed in NERC's IVGTF Task 1-6 will be a vital improvement to assess required flexibility.	Research & Development
	Set of best planning practices to design systems with sufficient system flexibility to accommodate targeted levels of VG should be documented.	Planning – Technical Guidelines

[3] IEEE Standard 1547 full revision effort is underway. NERC, tasks 1-3 and 1-7 team addressing disturbance ride-through requirements are participating in this effort in addition to national lab, some consultants, EPRI, solar developers, inverter manufactures, NREL and some utility representatives from the distribution side. NERC encourages BES reliability experts from utilities and ISOs to participate.

	Develop and collect metrics that measure flexibility needs for VG. For example, calculating a set of ramp and intensity metrics can provide insights on flexibility trends.	ERSTF
	The electric power industry should pursue research and development activities to assess the flexibility needs for the regional and interregional systems of North America as well as evaluate the benefits of flexible resources and technologies (i.e., DR, electric and thermal energy storage, and plug-in electric vehicles (PEVs)) on their respective systems.	Research & Development
	Advances and enhancements that inform all resources of the value of needed flexibility services and incent desired response while discouraging undesired response will be needed (e.g., a tariff for PEV owners that would discourages charging during peak hours and encourages charging during off-peak hours).	NERC Training & Education
	Maintenance scheduling may be more difficult in market regions where there is limited central authority to coordinate scheduled maintenance, and high levels of VG will likely have a significant influence. Methods to quantify the risk of both capacity shortfalls and flexibility shortfalls can be developed and tested in industry.	Planning – Technical Guidelines
	Generation planning: New methods have been developed to begin quantifying flexibility needs and risks of insufficient flexibility within generation expansion planning algorithms so that results balance investment in VG with investments in technologies providing the flexibility that VG requires.	Planning – Technical Guidelines
	The IVGTF suggests that those Balancing Areas that face significant integration of variable resources consider studying the benefits of sub-hourly scheduling to manage the integration of VG. Depending on the current or projected BA system characteristics, assuming sufficient transmission is available, there may be benefits to intra-hour interchange scheduling in the form of reduced ancillary services and more flexibility and ability to manage the variability, while still meeting the requirements of NERC's Reliability Standards.	ERSTF
Reactive Power & Voltage Control Requirements	NERC should promote greater uniformity and clarity of reactive power requirements contained in connection standards.	
		No Action
	NERC should consider initiating a SAR to establish minimum reactive power capability standards for the interconnection of	Standards Review and/or SAR

	all generators, and provide clear definitions of acceptable control performance.	
	Review applicability recommendations for generator interconnection requirement for reactive power.	Standards Review and/or SAR
	Review specification of Reactive Range defined over the full output range, and it should be applicable at the point of connection.	Standards Review and/or SAR
	Review and clarify MOD-025-1 Verification of Generator Gross and Net Reactive Power Capability, recommendation.	No Action – Completed
	Definition of Control Performance: Expected volt/var control performance should be specified, including minimum control response time for voltage control, power factor control, and reactive power control. An interim period for the application of precisely defined control capabilities should be considered.	Standards Review and/or SAR
Active Power Control Capabilities	NERC should investigate variable generating plants at an active power level where dynamic reactive capability is limited or zero.	Standards Review and/or SAR
	Include active power requirement during a voltage disturbance unless there is a reliability concern – PRC-024 standards.	Standards Review and/or SAR
	Require VG curtailment capability.	Operating – Technical Guidelines
	VG plants should be required to have the capability to limit the rate of power increase.	Planning – Technical Guidelines
	Plants must be able to accept commands to enable pre-selected ramp-rate limits.	Planning – Technical Guidelines
	Encourage or mandate the reduction of active power in response to high frequencies.	Planning – Technical Guidelines
	Consider requiring the capability to provide an increase of active power for low frequencies.	Planning – Technical Guidelines
	Summarize requirements of facility connection model grid code requirements: tests shall be performed (power ramping and power curtailment).	Enhancement to Modeling
Disturbance Requirements	In the short term, NERC should engage in current efforts to revise DER interconnection standards by providing information, supporting the efforts of IEEE with transmission reliability subject matter experts, raising industry, regulator,	NERC Staff

	and policy maker awareness, and encouraging the consideration of the explicit VRT and FRT for DERs.	
	The initial focus should be on potential ways to adopt minimum-tolerance thresholds for VRT and FRT in IEEE Standard 1547 while balancing against other important distribution issues such as safety and protection/coordination.	NERC Staff
	The task force also offers general guidelines on VRT and FRT specifications for distributed VERs and other DERs, for consideration in the P1547a process or future IEEE Standard 1547 revisions.	NERC Staff
	Provide guidelines to generator frequency and voltage protective relay settings.	Planning – Technical Guidelines
	Apply Control performance and disturbance control requirements.	No Action
Communications Requirements	Provide communications guidelines between VG plants and grid operators.	Operating – Technical Guidelines
	Technical Developments: Development of an operational infrastructure that provides visibility and control (direct or indirect) of distributed resources such as DR and PEVs.	Operating – Technical Guidelines
	For the Industry: Wind and solar plants require real-time meteorological and electrical data through SCADA systems using standard communication protocols for use in forecasting and system operation, including power, availability, curtailment, and meteorological data.	Operating – Technical Guidelines
	For the Standards: Review COM-002 (Communication and Coordination).	No Action – Completed
	Communication Recommendations for Wind Resources: Data and communication capabilities should be provided to the BA by all generation operating in the BA. Wind and solar plants should have the capability to send and receive real-time data (meteorological and electrical) through SCADA systems.	Operating – Technical Guidelines
Data Collections	NERC should design and implement a way to collect high-quality VG data that would help inform calculations of capacity value.	NERC Staff
	Design study reports that assess the harmonic performance of all wind and solar plants.	Research and Development

Harmonics and Subsynchronous Interaction	Provide a technical guidelines document to 1) understand the control interactions, 2) assessing the risk, and 3) if necessary mitigation of wind and solar plants located near series-compensated transmission lines or HVDC terminals.	Operating – Technical Guidelines
VG Power Forecasting	Use wind forecast error models and the forecast in unit commitment.	Operating – Technical Guidelines
	Standards revisions: FAC-001: Facility Connection Requirements	Operating – Technical Guidelines
	Standards revisions: TOP-002-2.1b: Normal Operations Planning	No Action
	Standards revisions: TOP-006-2: Monitoring System Conditions	No Action
	Standards revisions: BAL-002-1: Disturbance Control Performance	ERSTF
	Standards revisions: COM-002-2: Communications and Coordination	No Action
	Standards revisions: IRO-005-3.1a: Reliability Coordination – Current-Day Operation	No Action
Ancillary Services Requirements	Each Region or reserve-sharing group should permit contingency reserve deployment under imbalance energy circumstances.	Operating – Technical Guidelines
	The task team recommends that the generator interconnection requirements be modified to require this dispatchable control capability interface.	Operating – Technical Guidelines
	Regional market operators and other grid operating entities should develop the ability to consider transmission service by prioritizing variable resources when allocating curtailment responsibility to variable output resources during reliability-limited operating conditions.	Operating – Technical Guidelines
	Depending on the current or projected BA system characteristics, assuming sufficient transmission is available, use intra-hour interchange scheduling to increase the benefits in the form of reduced ancillary services, more flexibility and ability to manage the variability, while still meeting the requirements of NERC's Reliability Standards.	Operating – Technical Guidelines

Task 1-1: Standards Models for Variable Generation

Task 1-1 focused on the identified need for standard, generic, non-confidential, and publicly available power flow and stability models for VG technologies and for a task force to review existing NERC Modeling, Data and Analysis (MOD) standards to ensure high levels of VG can be simulated and appropriately addressed through the existing standards. Task 1-1 provided, at the time the report was issued, a detailed discussion of model and model validation in general, followed by an account of the current status of models for various VG technologies. It then provides a discussion of the relevant NERC MOD standards and where they will need to be augmented to properly address VG.

The Task 1-1 report[4] identified a need to have models that are standard (i.e., a defined model structure used by all commercial software tools), publicly available, and not specific to any particular design (i.e., "generic" and able to reasonably represent key performance relevant to BPS studies). Following the issuing of the report, much work has been done in the industry such as the release of a second generation of generic models[5] that have resulted in significant progress in meeting the needs identified in the Task 1-1 report. These models are now available in several commercial power system simulation software platforms used in North America.

The Task 1-1 report provides an overview of the models and modeling capability available at the time of issuing the report. Gaps and areas requiring further work were identified. As mentioned above, some of these gaps have since seen progress, while others are still being worked on. The modeling and model development discussed is primarily for power system power flow, short circuit, and stability analysis.

The report also addresses NERC modeling standards and recommended improvements. The regional model building manuals developed as part of MOD-11 and MOD-13 must provide sufficient clarity to model VG. These manuals may ask for best available models or generic models. The models cover the operational time frame and the 10-year planning horizon. The manuals do not currently cover the frequency for revalidating model data. While not included in the standards, more emphasis is currently being placed on meeting the Eastern Interconnection Reliability Assessment Group (ERAG) model of building manual requirements in addition to regional requirements. Specific recommendations are included for each of the MOD standards.

Key Findings and Recommendations

Annual NERC Model Development Process

It is important that the regional model building manuals developed as part of MOD-11 and MOD-13 provide sufficient clarity to model VG. These manuals may ask for best available models or generic models. These models cover the operational time frame and the 10-year planning horizon. The manuals do not currently cover the frequency for revalidating model data.

NERC Standards

The NERC Glossary of Terms would benefit from the inclusion of the term "Variable Generation." A possible definition was included in the Phase I report of the IVGTF.

[4] NERC Special Report on *Standard Models for Variable Generation*.
http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Standards%20Models%20for%20Variable%20Generation.pdf
[5] Specification of the Second Generation Generic Models for Wind Turbine Generators, WECC Report approved 1/23/14
https://www.wecc.biz/Reliability/WECC%20Second%20Generation%20Wind%20Turbine%20Models%20012314.pdf.

Table 3: IVGTF Recommended Standards Improvements		
Standard	**Definition**	**Recommendations**
MOD-011	Regional Steady-State Data Requirements and Reporting Procedures	Apply VG as a source of generation.
MOD-013-1	RRO Dynamics Data Requirements and Reporting Procedures	Include an explicit statement to cover VG.
MOD-024-1	Verification and Data Reporting of Generator Real Power Capability	Require wind units' total gross capability methods as the sum of the nameplate rating of all individuals.
MOD-025-1	Verification of Generator Gross and Net Reactive Power Capability	Clarification may be needed. Namely, VG reactive capability of the "power plant" is not entirely inherent in the individual generating units regarding how the total reactive capability of the power plant is defined.
MOD-026-1	Verification of Models and Data for Generator Excitation System Functions – SECOND POSTING	Standards are tailored explicitly to deal with synchronous-type generators, and items need to be clarified in these standards as they pertain to VG, particularly for: • Unit/plant size for validation • Validation of various technologies in a single plant • Validation of different control layers • Modeling and model validation • Future functionality • Modeling of protection • Issues related to the fuel source for VG model revalidation The latest versions of MOD 26 and 27 address these issues based on the above recommendations made in 2010.
MOD-27	Verification of Models and Data for Turbine/Governor and Load Control	
FAC-001	Facility Connection Requirements	NERC Reliability Standard FAC-001-1 should be expanded to clearly cover modeling requirements during the coordinated joint study phase of the Facility connection process. Simple generic models of VG may be adequate for the IES phase, and more detailed models may be needed for the IFS phase. Validation of the simple and detailed model parameters may be needed during commissioning.

Task 1-2: Methods to Model and Calculate Capacity Contributions of VG for Resource Adequacy Planning

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning.	Address consistent and accurate methods to calculate capacity values attributable to VG.	Michael Milligan March, 2011

Task 1-2 addresses consistent and accurate methods to calculate capacity values attributable to VG, including:

1. Technical considerations for integrating variable resources into the BPS.
2. Specific actions, practices, and requirements, including enhancements to existing or development of new Reliability Standards:
    a. Calculations and metrics, including definitions and their applications used to determine capacity contribution and reserve adequacy.
    b. Contribution of VG to system capacity for high-risk hours, estimating resource contribution using historical data.
    c. Probabilistic planning techniques and approaches needed to support study of BPS designs to accommodate large amounts of VG.

System planners require consistent and accurate methods to calculate the capacity contribution that can be attributed to VG to ensure the adequacy and stability of the bulk power grid. Long-term historical data sets allow for characterization and trending of key performance metrics, including those factors that contribute to resource availability and adequacy. VG, like wind and solar, does not have long-term historical data sets, and this lack of data limits the understanding of the long-term implications of VG performance. The potential output levels of VG show a large degree of variance over a wide geographic scale, so the ideal type and capacity contribution of VG will differ by location. Task 1-2 discusses the known characteristics of regional VG along with the current practices used by systems planners to predict VG output potential and capacity contribution during peak-demand hours to ensure grid reliability.

Key Observations

Comparison of reliability-based approaches used to calculate the effective load-carrying capability (ELCC) of VG is needed.

- LOLE Metric: The traditional approach is based on the Loss-of-Load Expectancy (LOLE) of 0.1 days/year as the reliability target. This approach considers only the peak hour of the days that have significant Loss-of Load-Probability (LOLP). This is typically a relatively small number of days because most of the year there is a surplus of capacity. A significant daily LOLE means that during the day there is some probability of insufficient generation, but the metric does not indicate the duration of the potential insufficiency, nor does it indicate the potential energy shortfall.
- LOLH Metric: A Loss of Load Hours (LOLH) metric considers all hours during which there may be a risk of insufficient generation. With high penetrations of VG, this may be an advantageous metric because of the variability of these resources. This provides a more accurate assessment of adequacy in the sense that all

hours are examined by the metric. However, unlike the daily LOLE, there is no generally accepted hourly target. Additional analysis is required to determine the relationship between LOLE and LOLH reliability targets.

It will be important to provide ongoing evaluation of the potential impacts of new VG resources on the grid.
VG is anticipated to increase substantially in the North American grid. Because prospective VG plants, by definition, do not already exist, obtaining data that can describe the likely behavior of future plants is critical for a number of reliability, adequacy, and integration tasks that are performed in the planning cycle. Because weather is the principle driver for load and for VG output, it is critical to maintain chronology between VG and load. Specific locations of future VG may not be known with certainty, and to evaluate the likely impacts, multiple scenarios may need to be evaluated. Because of these issues, it will be important to develop and maintain a public database of wind and solar estimated (future) production. Large-scale Numerical Weather Prediction (NWP) models or solar radiation and cloud cover models can be used to provide high-resolution wind power and solar power data. The value of this type of dataset has been shown in the Eastern Wind Integration and Transmission Study (EWITS) and the Western Wind and Solar Integration Study (WWSIS).

Industry education on metrics and calculation used for capacity contributions will provide a better outlook on the true nature of VG.
Based on the experience of many participants of the IVGTF Task Force 1-2, it seems apparent that the workings of LOLP, ELCC, and related reliability approaches are not always well understood. This highlights the need for the dissemination of information regarding the behavior and performance of these metrics.

The performance of VG should be tracked to understand the resource adequacy contributions of various technologies.
Calculating capacity value for existing VG sources requires chronological generation data that is synchronized with load data and other relevant system properties. Existing power system databases can be used to track this data, which would be useful in helping to better understand VG performance and operational issues (addressed by other work streams of the IVGTF). NERC already collects data to inform the GADS database. Although it is more data intensive than the GADS process, operational data from VG over the next several years will be extremely valuable in the assessment of capacity value and operational issues surrounding the use of VG.

Key Findings and Recommendations

The 1-2 report provides the reader with a general framework for determining the contributions and best use of VG in the bulk power grid. In order to ensure the proper allocation of the increase in VG, NERC suggests the following:

Metrics

- Additional research to compare traditional reliability targets (such as a LOLE of 0.1 day/year) to alternative metrics.
- LOLP, LOLE, or other related metrics should be used to calculate generation adequacy and capacity contributions of VG.
- **Planning reserve margin, calculated as a percentage of system peak, will become less meaningful with large penetrations of VG.**
- Industry to adopt more widely energy-related reliability metrics and targets as the share of VG increases in the power system; implement comparison of results based on these alternative metrics.

Multi-Area Reliability Adequacy

- Alternative approaches and assumptions regarding the treatment of interconnected systems should be transparent to the analysis.
- Development of one or more common approaches for addressing the impact of interconnected systems in the reliability assessments will be useful.

Alternative Approaches

- Planning reserve margin levels should be periodically benchmarked with, or derived from, an LOLP or related approach to resource adequacy to account for any changes.
- Simplified approaches should be benchmarked and calibrated to the rigorous ELCC calculations to ensure the validity of the approximation.
- The ramp response characteristic includes the rate of ramping required from flexible resources and the predictability of the ramp:
  - Measuring the maximum magnitude change over various time scales (e.g., 10 min., 30 min., 1 hr., and 4 hrs.), and unit start-up times would capture the rate-of-ramp aspect of ramp response.
  - Predictability needs to include components such as event forecast accuracy and advance warning.
- Study and validate resource adequacy approaches based on alternative study results comparisons.

Data Collection

In the time since the Task 1-2 report was written, there have been advances in modeling that now make it possible to do a good job of creating 5-minute data, which aligns better with how existing markets work. This would be a better match for analyses, not just because of Task 1-2, but also because of other production simulation modeling mentioned in this report.

- NERC should design and implement a way to collect data that would help inform calculations of capacity value.
- NERC should request that government agencies like the DOE, working with NOAA/NCAR and the resource assessment industry, develop annual high-resolution, modeled wind and solar power data on 10-minute time scales and 2 km or smaller geographic grids.

Education

- NERC should facilitate the dissemination of information about how LOLP-related reliability and adequacy calculations perform and what they measure.

Task 1-3: Interconnection Requirements for VG

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Interconnection Requirements for Variable Generation	Make recommendations for how NERC interconnection procedures and standards should be enhanced to address: • Voltage and frequency ride-through • Reactive and real power control • Frequency and inertial response criteria	Richard Piwko September, 2012

Task 1-3 addresses interconnection requirements for VG. Many of NERC's existing interconnection standards and procedures have been based on technical characteristics and physical capabilities of traditional power generation resources that employ synchronous generators. VG comprises any power generating facility where the source of the energy is not dispatchable. Wind and solar generation are the most common types of VG, though ongoing research may lead to increased utilization of tidal, wave, ocean thermal, and other resources. Some common characteristics of wind plants and solar photovoltaic (PV) plants include:

- The energy source is variable, influenced by atmospheric conditions, and predicted by day-ahead and short-term forecasting.
- VG plants are often comprised of multiple individual "generators" connected and operated in a coordinated manner.
- The power sources (such as wind turbines or solar panels) are connected to the electrical network via power electronics rather than synchronous generators.
- Responses to system disturbances are primarily determined by control functions, not the inherent electromechanical dynamics of synchronous generators.

Task 1-3 provides recommendations for how NERC interconnection procedures and standards should be enhanced to address voltage and frequency ride-through, reactive and real power control, and frequency and inertial response criteria, considering the evolving range of technical characteristics and physical capabilities of VG equipment.

Key Findings and Recommendations

1. Reactive Power and Voltage Control

Recommendations for Modification of Existing NERC Standards

NERC should consider revisions to the FAC and VAR standards to ensure that reactive power requirements for all generators are addressed in a technically clear and technology-neutral manner. As with all new or changing requirements, appropriate consideration should be given to the applicability to existing generators. Suggested updates are as follows:

- Consider adding a clarification to FAC-001 expanding R.2.1.3 or an appendix stating that interconnection standards for reactive power must cover specifications for minimum static and dynamic reactive power

requirements at full power and at partial power. Include how terminal voltage should affect the power factor or reactive range requirement (see Section 2.8.3 below for technical guidelines).

- Consider modifying VAR-001 to include the term "plant-level volt/var controller" (in addition to "AVR"), which is more appropriate for VG.

A large amount of VG, including most of the solar PV deployment, will be relatively small plants with capacity below the threshold specified in the existing NERC Registry Criteria, and connected at voltages below 100 kV. This includes residential and commercial systems, as well as larger plants connected to the distribution or sub-transmission system. To the extent that these systems, in aggregate, can affect the reliability of the BPS, the FAC and VAR standards should be extended or revised to govern them. A prospective NERC standard addressing reactive requirements for smaller plants should recognize that distribution-connected VG plants have traditionally been operated in power factor control mode.

General Recommendations for Standards Development and Reconciliation

For the most part, existing NERC and FERC interconnection standards were developed with synchronous generators in mind. As such, these standards do not fully define performance requirements for reactive power support. This has resulted in unclear, inconsistent, and sometimes inappropriate interconnection reactive power requirements for generators, especially VG. Specific recommendations are as follows:

- NERC should promote greater uniformity and clarity of reactive power requirements contained in connection standards that Transmission Operators have issued pursuant to FAC-001. NERC, FERC, and other applicable regional standards should be reconciled.
- NERC should consider initiating a SAR to establish minimum reactive power capability standards for interconnection of all generators and provide clear definitions of acceptable control performance.

Technical Guidelines for Specification of Reactive Power Requirements

VG technologies are technically capable of providing steady-state and dynamic reactive power support to the grid. Based on a review of best practices and operating experience, the report offers the following technical guidelines for specification of reactive power capability and control requirements for interconnection of generating plants to the transmission system:

- **Applicability:** The generator interconnection requirement for reactive power should be clearly established for all generator technologies. NERC should consider giving transmission planners some discretion for variance based on the characteristics of their transmission systems and the sizes of the generators.
- **Specification of Reactive Range:** The reactive range requirement should be defined over the full output range, and it should be applicable at the point of connection.
- **Impact of System Voltage on Reactive Power Capability:** It should be recognized that the system voltage level affects a generating plant's ability to deliver reactive power to the grid, as well as the power system's requirement for reactive support.
- **Specification of Dynamic Reactive Capability:** The standard should clearly define what is meant by "Dynamic" Reactive Capability by specifying the portion of the reactive power capability that is expected to be dynamic. A prospective standard should specify the minimum performance characteristics of the response in terms of response time, granularity (maximum step size), and repeatability (close-open-close cycling capability).
- **Definition of Control Performance:** Expected volt/var control performance should be specified, including minimum control response time for voltage control, power factor control, and reactive power control. An interim period for the application of precisely defined control capabilities should be considered.

- **Effect of Generator Synchronization on System Voltage:** Synchronization of generators to the grid should not cause excessive dynamic or steady-state voltage change at the point of connection. A 2 percent limit may be considered as a baseline.
- **Special Considerations:** NERC should investigate whether Transmission Operators can, under some conditions, allow variable generating plants to operate normally or temporarily at an active power level where dynamic reactive capability is limited or zero.
- **Technical Alternatives for Meeting Reactive Power Capability:** The reactive power requirements should be applicable at the point of interconnection.
- **Commissioning Tests:** Commissioning tests, which are part of the interconnection process, often include a test to demonstrate plant compliance with reactive power capability requirements.

2. Performance During and After Disturbances

Applicable Plants

The scope of PRC-024-1 should be broadened to cover smaller plant sizes. The current proposal of 75 MVA will miss many variable generator facilities that could impact the Bulk Electric System. The scope should be broadened to cover all projects under a Large Generator Interconnection Agreement (LGIA), or all projects greater than 20 MW. Another option is to extend the scope to any project greater than 10 MW in order to provide coverage for plants not included under IEEE 1547. This IVGTF task team could not come to a consensus on the exact plant threshold (10 vs. 20 MW or MVA). It is recommended that industry decide the appropriate threshold as Regional differences may be justified. Applicability should depend on total plant rating and should not be based on individual unit size.

3. Disturbance Ride-Through

Fault ride-through and frequency ride-through capability of generators will be covered by the NERC standards under development. TPL-001-2 will cover the planning assessment for new and existing generators to ensure that grid performance Reliability Standards are met. PRC-024-1 will provide additional clarity to the generator industry in terms of uniform requirements.[6] No additional requirements are needed for FAC-001-0.

Ride-through plots should be provided that specify both high- and low-voltage ride-through requirements. The zero-voltage ride-through should be equal to the three-phase fault-clearing time on the network. The zero-voltage ride-through is up to nine cycles but may be less depending on the clearing time. This should be made explicit in any requirement.

PRC-024 should clearly define performance requirements for unbalanced and balanced faults. The specification of voltage magnitude should define what voltage metric is applicable.

Voltage disturbance performance requirements, particularly high-voltage ride-through, should use the severity-cumulative duration form of specification to avoid unnecessary increase of VER plant costs to meet voltage disturbance durations that will never occur in practice.

It is not suggested that a NERC-wide requirement be mandated for riding through a rate-of-frequency change. If a standard is desired by individual operators, a rate-of-change ride-through requirement of 2.5 Hz/s appears

[6] Subsequent to the issuance of the Task 1-3 report the proposed Standard PRC-024 was changed to eliminate the voltage and frequency disturbance ride through requirements. The Task-1-3 report was based on a draft version of PRC-024 that would have required all new generators to ride-through voltage and frequency disturbances but that version was rejected by the NERC ballot body and the version that was adopted and accepted by the NERC board has no ride through requirements. The Task 1-3 recommendations might have been different had they been based on version of PRC-024 that was adopted in the spring of 2013.

adequate. (This rate of frequency change is stipulated in the current draft of PRC-024). There may be some regional differences where at least 4.0 Hz/s is required.

PRC-024 should define the performance required during and after disturbances and should make clear and unambiguous what remaining "connected" entails. It is not recommended that active power be required during a voltage disturbance unless there is a reliability concern. The sourcing of reactive power during a severe fault should instead be given priority over real power delivery, and the magnitude of reactive power should be consistent with pre-fault reactive power capability. The capability to supply reactive current during a fault varies with technology and product offerings, so a market to incentivize, but not require, the increased sourcing of reactive current during a voltage dip is recommended.

Disturbance performance requirements, including PRC-024, should indicate the maximum level of transmission contingency (e.g., N-1-1) that a plant should be required to ride through.

Disturbance performance requirements, such as PRC-024, should clearly define any requirement for repeated disturbances.

Transmission-interconnected VERs should not have any active anti-islanding functions enabled unless these functions are properly coordinated with all applicable stakeholders so that they do not detract from bulk transmission system transient or dynamic stability.

4. Power Recovery

It is not necessary to specify a detailed power recovery characteristic for variable generators in a standard. Detailed accurate models provided by the Generator Owner will be sufficient for interconnection studies. If performance criteria are not met, then the Transmission Owner/Planner can work with the Generator Owner to develop a mitigation plan.

Recovery after Blackout

It is reasonable to clarify the restart expectations of a generator facility following a disturbance. In some cases, the Transmission Operator provides a signal to the facility that prohibits automatic restarting after a severe grid event. FAC-001 could be modified to include a facility connection requirement to address generator facility restarting.

Standards for Manufactured Equipment

Current solar PV inverters designed to comply with IEEE 1547 are required to provide anti-islanding capability and disconnection requirements that are not compatible with the fault ride-through requirements recommended here. Although individual inverters may have capacities of the order of 500 kW, utility-scale PV plants may have hundreds of these units and hence have a plant capacity upwards of 100 MW. Furthermore, the inverters are listed according to UL-1741, which is based on the requirements of IEEE 1547. This report recommends that new standards be proposed for utility-scale PV plants in order to drive the industry toward the adoption of new inverter specifications, testing, and certification.

5. Active Power Control Capabilities

Require Curtailment Capability, but Avoid Requirements for Excessively Fast Response

VG can respond rapidly to instructions to reduce power output. In many cases, response is faster than conventional thermal or hydro generation. However, there have been cases where grid codes[7] have included

[7] The grid code specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances. It is divided into a Planning Code, Connection Conditions, Operating Code, Balancing Code, Data Registration Code, and General Conditions. Detailed definitions can be found at the NERC website.

excessive requirements for speed of step response to a curtailment order. This is technically challenging and should be avoided. A change (Δ) of 10 percent (%)/s for rate of response to a step command to reduce power output is reasonable. This rate of response to step instructions should not be confused with the imposition of ramp-rate limits, as discussed next. Active power considerations are not driving reliability requirements at this time.

Some conventional generation can reach or even exceed these rates, but most cannot. The project team is not aware of any NERC standards that specify rate of response to re-dispatch commands (of which curtailment is a subset) in this time frame. Typically, plants must respond to economic re-dispatch within minutes. Mechanisms such as markets or other incentives to encourage rapid rate of response from all generating resources should be considered.

Require Capability to Limit Rate of Increase of Power Output

VG plants should be required to have the capability to limit the rate of power increase. This type of ramp-up rate control capability has been required in some systems. This function should include the ability to be enabled and disabled by instruction from the Transmission Operator, BA, or Reliability Coordinator. Plants must be able to accept commands to enable pre-selected ramp-rate limits. Plants should be designed with recognition that ramp-rate limits should not be required under all operating conditions. VG plants should not be required to limit power decreases due to declines in wind speed or solar irradiation (i.e., ramp down rate limits). However, limits on decreases in power output due to other reasons, including curtailment commands, shut-down sequences, and responses to market conditions, can be reasonably required.

Encourage or Mandate Reduction of Active Power in Response to High Frequencies

VG plants should be encouraged to provide over-frequency droop response of similar character to that of other synchronous machine governors.

Consider Requiring the Capability to Provide Increase of Active Power for Low Frequencies

This is the other side of frequency control. VG plants should not be required to provide governor-like frequency response for low frequency under normal operating conditions. This is consistent with any conventional power plant operating at full throttle output (i.e., valves wide open). However, encouraging VG plants to have the capability to provide this response, and then establishing rules and possibly compensation for when such controls would be enabled, could be considered. This presumably would be a rare occurrence, as the economic penalty associated with enabling these controls is high.

Consider Requiring Inertial Response in Near Future

Some manufacturers are now offering inertial response for wind turbines. This is distinct from the previous two items on frequency response in that inertial response is faster and strictly transient in nature. Consequently, there is not a significant economic penalty associated with the use of this new feature.

Synchronous generators have inherent inertial response. It is not a design requirement. It is simply a consequence of the physical characteristics of the rotating masses connected to a synchronous generator. With the exception of Hydro-Québec, inertial response characteristics have not been specified in grid codes or interconnection requirements for wind plants. Furthermore, language describing this functionality in technology-neutral terms and subject to the physical reality of VG facilities is not presently available.

Requiring this function in the future as the technology matures and as grid operators and reliability organizations learn more about the need for inertial response characteristics from wind plants should be evaluated further. However, incremental costs should be carefully weighed against alternatives on both the supply and demand side for providing this capability.

6. Harmonics and Subsynchronous Interaction

Although harmonics and subsynchronous interaction issues can pose a reliability risk to the power grid in some instances, such risks are rare and only affect a small portion of VG plants. There is no need for NERC to develop interconnection criteria related to sub-synchronous resonance (SSR)/subsynchronous interactions (SSI) or harmonics at this time. However, it would be prudent for Transmission Owners and grid operators to:

- Consider design study reports that assess the harmonic performance of all wind and solar plants; and
- Until better understanding of the control interactions issue is gained, consider design study reports that assess the risk and, if necessary, mitigation of wind and solar plants located near series-compensated transmission lines or HVDC terminals.

7. Models for Facility Interconnection Studies

Discussion of Generator Unit/Facility Size Applicability

Accurate models are required for all generator facilities that are connected to or are planning to connect to the Bulk Electric System (100 kV and higher) regardless of size. However, NERC's current Statement of Registry Criteria is the governing document that defines applicability of entities to NERC Reliability Standards.

Ongoing model revalidation is currently covered by:

- MOD-024-1: Verification of Generator Gross and Net Real Power Capability
- MOD-025-1: Verification of Generator Gross and Net Reactive Power Capability
- MOD-026-1: Verification of Models and Data for Generator Excitation System Functions
- MOD-027-1: Verification of Models and Data for Turbine/Governor and Load Control

These standards were reviewed and reported on in the NERC special report, *Standard Models for Variable Generation*.[8] The ongoing detailed model validation may evolve to cover generator units or generator facilities 75 MVA or larger. This breakpoint covers at least 80 percent of the currently installed generation in North America and matches the NERC Statement of Compliance Registry Criteria, which is approved by FERC.

Generator facilities smaller than the 75 MVA threshold—especially VG facilities—may experience rapid changes in control performance over their lifetimes due to equipment upgrades and replacements. These changes should be captured in updated models. However, substantial modifications on facilities less than 75 MVA may not be captured by the FAC-001 standard or MOD standards.

NERC Standard FAC-001-0 Modifications

Transmission Owners' and Transmission Operators' interconnection procedures are part of their respective Open Access Interconnection Tariffs, such as the FERC Large Generator Interconnection Procedures. NERC Reliability Standard FAC-001-1, Facility Connection Requirements, approved by the NERC Board of Trustees February 2012, addresses a number of issues related to FAC-001-0, including the applicability of FAC-001-1 to Generator Owners as well as Transmission Owners.

> *R3.1.17 Generation facility modeling data, including appropriate power flow, short circuit and dynamic models, and verification requirements.*

[8] Special Report – *Standard Models for Variable Generation*
http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Standards%20Models%20for%20Variable%20Generation.pdf

Modeling needs for the interconnection process are different than modeling needs for evaluation of regional grid performance. To clarify this point, we recommend that the following statement be added to the FAC-001-0 standard as an appendix for clarifying R3.1.17:

> "Preliminary or approximate power flow and dynamic models may be adequate for the preliminary assessment of interconnection impacts, or to represent existing and proposed projects that are not in the immediate electrical vicinity of the facility being studied. However, detailed dynamic (and possibly transient) models for the specific equipment may be needed for the System Impact Study and Facilities Study to represent the facility and other equipment in the electrical vicinity. Generic non-proprietary publicly available models are more appropriate for the NERC model building process covered by existing MOD standards, although validated generic models with specifically tuned parameters may be adequate for interconnection studies. The models for interconnection studies must be acceptable to the Transmission Owner in terms of simulation platform, usability, documentation and performance."

The above recommended sub-requirement R3.1.17, as with all of the sub-requirements in FAC-001-0, leaves it to the Transmission Owner to "fill in the blanks" or develop specific requirements that will be applied to facilities intending to interconnect to their network. This can lead to inconsistencies across the grid. In order to avoid inconsistencies, several facility interconnection requirement documents or grid codes were reviewed to try to develop a recommended best practice to aid Transmission Owners. A review of grid codes as of 2011 can be found in Appendix 5 of the Task 1-3 report. However, as mentioned previously, these grid codes are in a constant state of change.

Summary of Facility Connection Model Grid Code Requirements

After reviewing the interconnection procedures and standards of several grid codes with respect to models and model validation, several key features could be considered for adoption by Transmission Owners:

- Preliminary model data may be used for the initial feasibility study of a variable generator interconnection project.
- The best model available should be used for the final System Impact Study or Facilities Study. These models can be user written and require nondisclosure agreements.
- The detailed dynamic model must be accurate over the frequency range of 0.1 to 5 Hz. Time constants in the model should not be less than 5 ms.
- The detailed dynamics model must have been validated against a physical or type test.
- Verification of detailed model performance should be confirmed during commissioning to the extent possible. The following tests shall be performed:
  - primary/secondary voltage control
  - low-voltage and high-voltage ride-through
  - power factor/reactive power capability
  - power ramping and power curtailment
- Verification of non-proprietary model accuracy may be performed by simulation tests compared with the detailed model performance.
- At the end of the commissioning tests, the Generator Owner should provide a verified detailed model and a non-proprietary model, ideally in IEEE, IEC, or other approved format, for ongoing regional studies such as TPL-001.

8. Communications between Variable Generation Plants and Grid Operators

The Task 1-3 project team recommends that the basic requirements for communications and control between grid operators and VG plants be based on the existing policy for conventional generators.

- VG plants should send a minimum set of monitoring data to the grid operation via the SCADA network.
- VG plants should receive and execute command signals (power limit, voltage schedule, ramp-rate limit, etc.) sent from the grid operator via the SCADA network.
- VG plants should have trained on-call plant operators who can receive calls from the grid operator 24/7 and who can immediately execute verbal commands. The plant operators would not need to be located at the plant, provided they have secure remote control capability for the plant.

Task 1-4: Flexibility Requirements and Metrics for Variable Generation Implications for System Planning Studies

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Flexibility Requirements and Metrics for Variable Generation: Implications for Planning Studies	Develop the planning and operational practices as well as the methods and resources needed to integrate VG resources into the BPS.	Michael Milligan August, 2010

Task 1-4 focuses on the IVGTF work plan directive: *Resource adequacy and transmission planning approaches must consider needed system flexibility to accommodate the characteristics of variable resources as part of bulk power system design.* The NERC Planning Committee's Resource Issues Subcommittee should study changes required to current resource adequacy assessment processes to account for large-scale VG integration. Considerations should include ramping requirements, minimum generation levels, required shorter scheduling intervals, transmission interconnections, etc.

This report concentrates on how to assimilate or consider VG into resource and transmission planning. Data needs are identified and the report makes recommendations to responsible NERC entities. The goals of the report are to:

- Study resource and transmission planning process changes required to include VG characteristics; and
- Identify data requirements to support resource adequacy assessment and determine which NERC entities should collect, retain, and provide this data.

The Task 1-4 report documents the extent to which resource adequacy and transmission planning processes may need to consider system flexibility to accommodate the characteristics of variable resources as part of BPS design. Planning studies have historically concentrated on the concept of adequacy. Task Force 1-4 developed a study approach that will:

- Describe the characteristics of the net load to be served by conventional generation and the need for flexibility;
- Document the experience of power systems that already have a relatively high penetration of VG;
- Identify sources of flexibility;
- Discuss metrics that can be used to characterize flexibility;
- Discuss the tools required for system planning to include system flexibility and to present conclusions and recommendations.

This information will be used to determine how flexibility could be accounted for and measured in existing studies, whether flexibility should be accounted for differently in planning studies, and what kind of metrics could be needed to measure flexibility.

Historically, system planning studies generally have not explicitly addressed the need for system flexibility, as the characteristics and performance of conventional generating technologies included design requirements to meet

variability and randomness from demand, which is well understood and predictable. Power system variability was addressed in resource planning studies by identifying the most economic resource mix to meet a time-varying load profile. In transmission planning studies, it was addressed by evaluating loss of source in the local area. However, for reliable operation, adequate amounts of system flexibility are required to accommodate large amounts of VG. Without this flexibility, the penetration of VG may be limited to ensure the reliability of the BPS. Therefore, planning and design processes will need to change, depending on basic system characteristics, to provide the flexibility needed to meet targeted levels of VG. Development of appropriate flexibility metrics is an important aspect in facilitating these new processes.

The Task 1-4 report documents:

- How VG will increase the need for the power system to be able respond to increased variability;
- How power systems have begun to address the need for increased flexibility;
- A framework to measure flexibility; it concludes with how recent large-scale VG integration studies provide a framework for addressing flexibility in planning studies; and
- Recommendations as to how a set of best practices can be developed for modifying planning tools now to address flexibility, and how the state of the art for conducting system planning studies can be advanced to more effectively capture the need for increased flexibility.

Charting new ground is always challenging. The development of metrics for a multi-dimensional concept like power system flexibility and incorporating it into planning studies presents a significant challenge. This report provides a framework to accomplish that end and a foundation for future work.

As the penetration of VG increases, system flexibility requirements will also increase. This flexibility manifests itself in terms of the need for dispatchable resources to meet increased ramping and load following, some of which could occur rather unexpectedly (i.e., not forecast). This flexibility will need to be accounted for in system planning studies to ensure system reliability. Enhancements to existing system planning practices will be required to account for increased flexibility necessitated by the integration of VG. System planning studies focus both on the reliability of the power system as well as optimizing the overall economics of the power system; here, the emphasis is on reliability.

The primary data for assessing system flexibility requirements resulting from the integration of VG is the net load (load minus VG in all time frames). Currently, there is no universally accepted measure or index of flexibility that would facilitate comparison across systems. The availability of such an index could potentially facilitate the evaluation of flexibility.

Current system planning practices and tools with appropriate modifications and enhancements have provided a basis for evaluating the impact of VG on system flexibility needs. For example, net load impacts can be evaluated explicitly or implicitly with tools (such as a chronological production cost simulation model) that typically model hourly or sub-hourly operations and all relevant physical constraints, including minimum-generation-level ramp rates and transmission constraints. Since the task 1-4 report was written, advances have occurred in production simulation modeling (more granularity and better accuracy) to obtain five-minute models instead of hourly models, although hourly models are still useful. A number of recently completed studies with the objective of evaluating the integration of VG have successfully used these models. They include studies by the California ISO, the Ontario Power Authority, the Electric Reliability Council of Texas (ERCOT) and, more recently, the Department of Energy (*Eastern Wind and Transmission Integration Study*)[9]. All of the studies, to some extent, address how VG impacts the need for system flexibility. The studies collectively covered the following aspects:

[9] Department of Energy (DOE) Eastern Wind and Transmission Integration Study http://energy.gov/sites/prod/files/2013/12/f5/47078.pdf

- Production cost models, which includes transmission models to assess the interaction between the dispatchability of wind and transmission;
- Extensive use of statistical analysis of hourly and sub-hourly wind plant output and net-load data (mainly simulated but some historical data was used where available) to ensure that production cost models adequately capture ramp rate and minimum generation constraints and account for regulation requirements;
- Wind forecast error models to account for operational impacts caused by the uncertain nature of VG (wind forecasting is covered by Task 2-1); and
- Resource adequacy models (e.g., LOLP models) that reflect the much lower availability or lower load-carrying capability of VG (this topic is covered in detail by Task 1-2).

In addition, these studies identified data needs specific to incorporating VG into planning studies:

- Determination of the interconnection point for the VG
- Specification for and identification of data sources that facilitate the accurate modeling of VG resources.
- Models and associated data that enable the accurate simulation of the output of VG and ensure output profiles are contemporaneous with the load profile and represent the uncertainty in the profile
- Data needed to conduct both transient and voltage stability analysis for wind plants

Important planning topics, such as system stability analysis and transmission planning, are neglected by many of these studies but are recognized as important and in need of attention. In particular, the transmission planning that accounts for the flexibility needs is a topic that has hardly been addressed. For example, the more variable nature of power flows driven by the VG output may need to be addressed by the integrated transmission and generation planning process.

Many of the studies found that the systems already possess the needed flexibility, particularly at lower VG penetration levels; therefore, there may be no need to develop additional sources of flexibility.

The integration studies should be reviewed to identify best practices and to develop guidelines that can be adopted immediately for the use of and enhancements to existing planning tools for evaluating the flexibility needs that arise from the integration of VG. It should be recognized in this review process that many important issues are simply not covered and require additional study and effort to develop meaningful guidelines.

In addition to identifying the impact of VG on the characteristics of system flexibility and their implication for system planning, this report also identifies the many sources of increased flexibility available to system planners and operators. New sources such as demand-side management may be particularly attractive and need further study. Many of the most important sources may not be physical, but institutional; i.e., they unlock the availability of existing physical flexibility (e.g., forecasting, market design, etc.). This indicates that a portfolio of alternatives exists and is available to a power system to meet its flexibility requirements. These options would need to be evaluated within the context of any new enhanced system planning framework.

In summary, high penetrations of VG will result in the need for increased flexibility, which planning studies will need to account for. This report provides examples of how power systems that already have high levels of VG are adjusting operating practices and market structures in response to the increased variability. The task force began the challenging effort of developing a metric for flexibility but left further development to NERC and industry. Finally, the report did not identify specific changes to planning practices to account for the impact of VG but believes that a set of best practices to account for flexibility in planning studies now can be developed. A starting point is a number of excellent integration of VG studies that have been conducted in the recent past.

Summary of Recommendations

- Probabilistic planning methods being developed in the ongoing work of NERC's IVGTF Task 1-6 will be a vital improvement to assess required flexibility.
- System planners should document a set of best planning practices to design systems with sufficient flexibility to accommodate targeted levels of VG.
- The NERC Reliability Metrics Working Group (RMWG), after provision of metric templates, develops agreed-upon metrics:
  - Develop and collect metrics that measure flexibility needs for VG. For example, calculating a set of ramp and intensity metrics can provide insights on flexibility trends.
  - Compare projected and actual annual energy levels from VG.
  - Measure VG performance factors such as capacity factors and peak coincidence factors.

Task 1-5: Potential Reliability Impacts of Emerging Flexible Resources

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Potential Reliability Impacts of Emerging Flexible Resources.	Identify the need to assess reliability implications of integrating: • Plug-in hybrid electric vehicles • Storage devices • DR programs	Daniel Brooks November, 2010

The additional system variability and the reduced on-line conventional synchronous generation that may occur as more variable energy is delivered presents new challenges for power system operators to manage in the time frames of milliseconds to many days. To maintain the reliability of the BPS as more VG is integrated and other system enhancements potentially impact the ramp requirements of the system, sufficient and appropriate operational flexibility will be needed to respond to the resulting additional variability and uncertainty.

The Task 1-5 report summarizes the potential contributions that may be obtained in the future from emerging sources of flexibility such as DR, electric and thermal energy storage, and PEVs. As part of this assessment, the capability of each of the identified emerging resources to provide system flexibility/reliability functions and services was qualitatively evaluated for 10 specific characteristics: inertial response, primary frequency response, regulation load following, dispatchable energy, contingency spinning reserves, contingency non-spinning reserves, replacement reserves, VG tail event reserves, and voltage support. There are numerous challenges to quantifying the potential impact of these emerging flexible resources on bulk system reliability, including the lack of flexibility metrics, the uncertainty in quantifying future system flexibility needs, and the uncertainty due to the availability of the emerging flexible resources and other conventional resources that can supply flexibility. Consequently, this report provides a qualitative analysis of the potential of DR, distributed energy storage, and PEV technologies to provide the 10 specified reliability functions 10 years in the future.

An important conclusion from this assessment is that the emerging flexible resources evaluated—DR, distributed energy storage, and PEVs—offer the potential to support many of the flexibility-related reliability functions that may be challenged as VG levels increase. While many of these technologies have not yet been applied to providing specific reliability functions, in many cases there do not appear to be any technical limitations in doing so. The potential market penetration of these emerging resources in providing the reliability functions is dependent on commercial and policy considerations that may or may not support development of these capabilities. Although a particular emerging flexible resource may be technically capable of providing specific reliability functions, the extent to which it is developed will be influenced by whether it is economically viable relative to other available potential sources.

Assuming that future commercial and market policy circumstances perpetuate present trends, these emerging resources are most likely to have the most significant impact on the reliability functions that allow for the longest response times and limited duration of response, such as spinning and non-spinning reserves. This is primarily due to the high potential of loads to participate in these reliability services, the growing record of accomplishment of DR already providing these services, and the large potential resource base that already exists. The potential aggregate impact on the faster response, longer duration, or higher frequency of deployment reliability functions

such as regulation or dispatchable energy is more moderate. These characteristics are not as well suited for a wide range of loads to supply. While many energy storage technologies and PEVs are technically capable and able to provide these services, they are either not currently commercially available or there is uncertainty as to whether sufficient development of the resources will have more significant impact over the next 10 years.

Key Findings and Recommendations

The electric power industry should continue research and development activities to assess the flexibility needs for the regional and interregional systems of North America and evaluate the benefits of flexible resources and technologies on their respective systems.

If all resources are provided equal opportunity and information as to power system reliability needs, then system reliability requirements, markets, and commercial viability should determine what resources provide specific reliability functions to the grid. If the emerging flexible resources addressed in this report are to play a significant role in providing the additional flexibility needed to accommodate high levels of VG, the barriers and limitations identified in this report must be addressed. Limitations related to the resources themselves (e.g., technological limitations or commercial viability) will be addressed to the extent possible by technology developers if those entities determine there is broader economic incentive to do so. Other external limitations, however, need to be addressed in order for technology developers to make decisions on technology investments. To that end, it is recommended that the following be addressed:

Technical Developments

Development of an operational infrastructure that provides visibility and control (direct or indirect) of distributed resources such as DR and PEVs

- In order for the emerging distributed resources to be significant contributors to the bulk system reliability functions, appropriate communication systems and methods of aggregating the resources into larger resource blocks are likely needed. System operators will need to understand the operational state and energy capacity available to the system in real time via full integration into energy management systems (EMSs) and market operation systems. This development includes technical, administrative, and commercial aspects.
- Technical developments are needed to ensure proper communication capabilities and integration into EMS and market operation software platforms. Aggregation of the resources into larger blocks will require developing the administrative processes to aggregate and bid the blocks of resources into the appropriate markets.

Market Developments

Adjust market rules that unnecessarily limit the types of resources for providing specific reliability functions. Some markets specifically designate some classes of resources as unable to participate in supplying some services.

- To the extent that there are no technical limitations that would prevent a resource class from reliably supplying a given service, market rules should be adjusted to allow a variety of resource types to participate within stated performance specifications while ensuring that there are no follow-on adverse reliability consequences. Resource developers can then determine whether they can package any resource type to meet the performance criteria in an economically viable manner. Thus, market rules should be reviewed in all Regions to remove any unnecessary restrictions.
- Develop retail tariffs for PEV owners that would encourage charging during off-peak hours.

Standards

Adjust regional or federal Reliability Standards that limit resources that can be used for providing specific reliability functions.

- Similar to market rules, Reliability Standards may also limit certain resource groups from providing some reliability functions. For example, the NERC Glossary definition of spinning reserve references "unloaded generation," which has been interpreted as prohibiting load from participating. As with market rules, federal and regional Reliability Standards should be adjusted, if necessary, to allow all resource groups to participate in providing reliability services within specified performance criteria.

Education

It is important to raise owner and operator awareness of the potential benefits of offering incentives related to flexibility services. An example would be adjusting market prices to encourage a desired response from customers while at the same time discouraging an undesired response (e.g., developing a tariff for PEV owners that would encourage charging during off-peak hours and discourage charging during peak hours).

Task 1-6: Probabilistic Methods

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Probabilistic Methods	Summarize the potential influence on power system operating and planning decision problems of VG increased uncertainty.	Michael Milligan July, 2014
	Describe the role that probabilistic methods can play in improving the basis on which the various decisions are made.	

The IVGTF report highlighted the need for risk assessment and probabilistic methods to assist in the integration of VG. It did so primarily in the context of planning, but numerous references throughout the report also suggested that operations could benefit from improved methods that can broadly be referred to as probabilistic methods. Task 1-6 focused on probabilistic methods and is reflective of the increased attention that these methods are getting. Variability and uncertainty are not new to the power system, and part of this increased attention on probabilistic methods reflects advancements in computing speed and algorithms; methods that were previously intractable due to data size and computer processing time are increasingly within our reach. But growing levels of wind and solar energy are serving as catalysts for these efforts. For example, the NERC *Summer Reliability Assessment* points out that more probabilistically based methods will be needed as the penetration of wind energy and solar energy increases on the BPS.

To various degrees, other IVGTF tasks are related to probabilistic methods. Task 1-2, "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning," and Task 1-4, "Flexibility Requirements and Metrics for Variable Generation: Implications for System Planning Studies," are particularly relevant and in many ways are subsets of the probabilistic methods reported in Task 1-6.

The objective of Task 1-6 is to summarize the potential influence on power system operating and planning decision problems of increased uncertainty caused by high VG penetration levels, and to describe the role that probabilistic methods can play in improving the basis on which the various decisions are made.

NERC is adopting more probabilistic methods in general. For example, NERC is running a Pilot Probabilistic Assessment to produce enhanced resource adequacy metrics for the Long-Term Reliability Assessment. NERC has traditionally gauged resource adequacy using a deterministic Planning Reserve Margin metric. The pilot is investigating two probabilistic metrics: Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE). Unserved energy can be monetized, although this can be difficult to do.

Key Findings and Recommendations

- **Reserves**: The level of specific reserves needed for VG integration is broadly understood; however, specific methods have not been rigorously tested and compared. The application of stochastic methods appears promising but needs validation and acceptance if they are to be successfully used.
- **Dispatch**: There is emerging work on probabilistic methods to dispatch conventional generation to minimize cost and maintain reliability in the presence of high levels of VG; however, there is a gap between academic work and practice as a result of limited experience with high levels of VG.

- **Commitment:** There has been considerable interest in stochastic unit commitment. Methods and approaches vary, and most of this work resides in the academic/research domain. Collaboration to evolve and move these methods into actual practice, when appropriate, is needed.
- **Maintenance:** Maintenance scheduling may be more difficult in market regions where there is limited central authority to coordinate scheduled maintenance, and high levels of VG will likely have a significant influence. Industry can develop and test methods to quantify the risk of both capacity shortfalls and flexibility shortfalls.
- **Generation planning**: New methods have been developed to begin quantifying flexibility needs and risks of insufficient flexibility within generation expansion planning algorithms, so that results balance investment in VG with investments in technologies that provide the flexibility that VG requires. There is room for improvement in these methods, as well as a need to evolve and move these approaches from the research community to industry practice.
- **Transmission planning**: There is evidence that stochastic approaches to transmission planning may yield more robust solutions; combining such methods with co-optimization of generation and planning decisions is particularly appealing but computationally challenging. However, these methods are new and emerging, and additional research and deployment of such methods may be useful.

Additional General Recommendations

- Work to develop and demonstrate efficient probabilistic techniques and solutions that are capable of addressing industry problems.
- Improve the understanding of probabilistic methods within the industry. The research community needs to work more closely with the industry to clearly demonstrate the benefits of probabilistic methods. The industry needs to clearly communicate shortcomings in deterministic methods and areas where probabilistic methods can be most fruitful. Cooperative efforts of the research and industry communities are needed to overcome the challenges in terms of both understanding and demonstration.
- More and better data is needed to allow the research and demonstrations to be meaningful and realistic—from real power systems, from VG resources, and for future VG deployment scenarios. Collecting and maintaining large data sets can be expensive, however, and stochastic methods generally require data that may not be readily available. Industry should discuss the trade-offs and costs versus benefits of collecting data that could help inform stochastic methods and the more rigorous assessments of various risks associated with power system planning and operations with high levels of VG.
- Because of the potential for a significant increase in the development and application of stochastic methods to help analyze the impacts of VG, NERC should perform a biannual assessment of development in this area. The IVGTF would be an appropriate home for this work.

Task 1-7: Performance of Distributed Energy Resources During and After System Disturbance – Voltage and Frequency Ride-Through Requirements

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Performance of Distributed Energy Resources During and After System Disturbance Voltage and Frequency Ride-Through Requirements	Discusses FRT and VRT potential requirements for VERs connected to distribution facilities and the potential BPS reliability impacts if VERs do not remain interconnected, stable, and operational during and after normally expected momentary system disturbances.	Mahendra Patel December, 2013

A large amount of distribution-connected generation may have a significant effect on the reliability of the BPS. Existing interconnection requirements for Distributed Energy Resources (DERs) do not specifically take into account potential effects on bulk system reliability. Of particular concern to BPS reliability is the lack of disturbance tolerance, which entails voltage ride-through (VRT) and frequency ride-through (FRT) capability. Under high-penetration scenarios, it is possible for a large amount of DERs to trip on voltage or frequency due to a transmission contingency, which could potentially affect BPS stability. The need for high-frequency tolerance is being discussed as part of a current FERC stakeholder consultation on interconnection procedures for small generators'[10] distribution-connected VERs. Like all other DERs, these resources are required to comply with IEEE Standard 1547, which requires DERs to disconnect from the grid within a short period of time after voltage or frequency falls outside a certain range. The results of the IEEE Standard P1547a ballot were announced in September 2013, and the outcome was that VRT and FRT capabilities are now permitted but not required.

In North America, VRT and FRT standards for both BPS-connected and distribution-connected generators are in a state of evolution. NERC Reliability Standard PRC-024-1 was recently approved as a relay-setting requirement. The standard requires that generator voltage and frequency relays not be set to trip within the specified frequency and voltage performance envelopes unless it is necessary to do so to protect equipment or meet one of several other exceptions. With respect to disturbance tolerance, DER interconnection standards are inconsistent with the direction in which bulk system standards are evolving.

Task 1-7 evaluated the possible exposure of negative reliability impact on the BPS due to the lack of VRT and FRT requirements for DERs and provides general guidelines for the revisions to IEEE Standard 1547 to minimize this negative impact. It discusses FRT and VRT potential requirements for VERs connected to distribution facilities and the potential BPS reliability impacts if VERs do not remain interconnected, stable, and operational during and after normally expected momentary system disturbances. The task force also reviewed potentially inconsistent and conflicting requirements in existing standards for BPS-connected and distribution-system-connected VERs. In addition, Task 1-7 provided guidelines for suggested changes in the VRT and FRT requirements for distributed generation that may be necessary to maintain power system reliability and provided recommendations for changes needed in requirements to preserve the expected levels of power system reliability. Task 1-7 did not address reactive requirements of VERs for voltage control or voltage regulation, though task force members strongly feel they are essential and can have significant contribution in normal operation as well as reliability of the system. Task 1-7 also did not address reactive injections during system faults.

[10] See FERC Docket No. RM13-2-000.

Key Findings and Recommendations

In North America, IEEE Standard 1547 is the de facto standard for DER interconnection.[11] The lack of voltage and frequency disturbance ride-through requirements in the standard has the potential to adversely affect the reliability of the BPS under conditions of relatively high DER penetration levels expected in the future. While NERC's authority is solely to ensure BPS reliability, the task force concludes that large amounts of distribution-connected resources, in aggregate, can pose risks to the reliability of the BPS.

To mitigate these potential impacts, IVGTF Task 1-7 recommends that the voltage and frequency disturbance trip levels in IEEE Standard 1547 be revised and explicit disturbance tolerance requirements be adopted. This section summarizes the IVGTF 1-7 task force's guidance for future efforts to update DER interconnection requirements.

When the IVGTF Task 1-7 report was created, two general recommendations for NERC actions had been provided, followed by several suggested general guidelines for consideration by the IEEE 1547 participants, recognizing that specific requirements would have to be established through a stakeholder process. The recommendations offered were motivated by the relatively rapid deployment of distribution-connected VERs in some areas, particularly PV; however, they are intended to apply to other DERs as well.

One of the challenges is that, while high penetration of DERs can have an impact on bulk system reliability, NERC Reliability Standards that require relays on BES generators to be set to allow voltage and frequency ride-through do not directly apply. The task force believes that NERC and other BPS stakeholders can play a constructive role in ensuring that the reliability implications due to lack of disturbance tolerance for distributed VERs and other DERs are addressed. The general recommendations that have been offered are:

- In the short term, NERC should engage in current efforts to revise DER interconnection standards by providing information; supporting the efforts of IEEE with transmission reliability subject matter experts; raising industry, regulator, and policy maker awareness; and encouraging the consideration of the explicit VRT and FRT for DERs. The initial focus should be on potential ways to adopt minimum-tolerance thresholds for VRT and FRT in the IEEE Standard 1547 while balancing against other important distribution issues, such as safety and protection/coordination.
- In the longer term, NERC should establish a coordination mechanism with IEEE Standard 1547 to ensure that BPS reliability needs are factored into the revision efforts of future DER interconnection standards. To date, BPS stakeholders have participated only sporadically in the IEEE Standard 1547 process. As a result, VRT and FRT concepts receive limited consideration and may have been outweighed by distribution system protection concerns. This liaison process would be timely for the full revision to begin in 2013 or early 2014.

The task force also offers general guidelines on VRT and FRT specifications for distributed VERs and other DERs for consideration in the P1547a process or future IEEE Standard 1547 revision.

The 2014 draft phase of the IEEE Standard is now underway with strong support in enhancing the ride-through requirements. These enhancements will, in the future, allow for DERs to regulate voltages and to support grid frequency. There is reasonable potential that this new version of the IEEE Standard 1547 may carry out NERC's IVGTF Task 1-7 recommendations on voltage and frequency ride-through requirements. However, there is also substantial risk that various interests may introduce clauses that essentially nullify the ride-through requirements, such as to make these requirements only applicable where they do not require any changes or enhancements of equipment capability. Continued monitoring of the IEEE Standard 1547 development is essential to ensure that effective ride-through requirements are enacted.

[11] Other international organizations have also adopted the IEEE Standard.

Task 1-8: Potential Bulk System Reliability Impacts of Distributed Resources

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Potential Bulk System Reliability Impacts of Distributed Resources	Identify the potential impacts of DER to reliability.	Daniel Brooks August, 2011
	Identify potential mitigating strategies.	
	Review existing NERC Registry Criteria specific to DER applications.	
	Propose potential future approaches to ensure continued reliability in systems with large amounts of DER.	

Task 1-8 differs from the other IVGTF tasks in the following respects:

1. Task 1-8 focuses on the bulk system impact of distributed resources; and
2. Task 1-8 considers the bulk system impact of all distributed resources, not just VG resources.

Task 1-8 addresses the potential BPS reliability concerns arising from the integration of large amounts of distributed resources, such as distributed solar PV, PEVs, distributed electric storage, and DR programs.

The following potential bulk system reliability impacts of high levels of DER have been identified:

- Non-dispatchable ramping/variability of certain DERs.
- Response to faults: lack of low-voltage ride-through, lack of frequency ride-through, and coordination with the IEEE 1547 interconnection standards for distributed generation, which is presently being revised.
- Potential system protection considerations.
- Under-Frequency Load Shedding (UFLS) and Under-Voltage Load Shedding (UVLS) disconnecting generation and further reducing frequency and voltage support.
- Visibility/controllability of DERs.
- Coordination of system restoration.
- Scheduling/forecasting impacts on base load/cycling generation mix.
- Displacement of bulk system resources that provide reactive power and voltage control and active power and frequency support to the system.
- Impacts on forecast of apparent load seen by the transmission system

These issues may impact the bulk system at different levels of penetration, depending on the characteristics of the particular area to which the DERs are connected. Some factors will need to be managed by technical requirements (grid codes) for the DER itself, while others need the bulk system operator to adapt new planning or operational methods. Significant amounts of DERs can affect the power flow on the transmission and sub-transmission systems, which can result in thermal overloads or significant changes in profile. The uncertainties

associated with the variable output (in aggregate) can create additional uncertainties in net demand to be served by transmission and balancing resources, with an added complication to the system operator of limited monitoring and control of the output from distributed resources. Certain regions, such as Hawaii or Germany, are already seeing significant challenges of the type outlined here. Studies and real world experience have shown the potential impact of significant penetrations of DERs. In particular, much attention has been focused on both the impact of variability and uncertainty, which can be invisible to the bulk system operator, and low-voltage or low-frequency response of DERs. High DER penetrations have been shown to affect the transient and small-signal stability of the system. This can be either positive or negative depending on the type of DER (e.g., inverter-connected DERs can adversely or beneficially affect stability depending on the control schemes employed).

Key Findings and Recommendations:

While specific recommendations for guidelines or standards are not provided, the following general recommendations are made:

Metric and Additional Research

1. NERC, state regulators, and/or industry should continue development of an analytical framework and basis for understanding the potential adverse reliability impacts and how the magnitude of these reliability impacts changes with penetration of DERs and system configuration/composition.
2. As many DER issues may be beyond the scope of NERC's authority, and since it may be feasible to address these issues through non-NERC avenues (such as market rules, vertically integrated operations, or state programs), it is recommended that NERC work with the affected entities in the different regions, including state agencies having jurisdiction over DERs, RTOs, and vertically integrated utilities, to develop appropriate guidelines, practices, and requirements to address issues resulting from DERs that impact the reliability of the BES.

Technical Developments

Based in part on the analytical results from the first recommendation in the metric and additional research above, and the broad experience of generation, transmission, and distribution owners and operators, specific recommendations for changes to operating and planning practices, state programs, and pertinent NERC Reliability Standards should be developed.

Task 2-1: VG Power Forecasting for Operations

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Variable Generation Power Forecasting for Operations	Discuss the forecasting requirements for the 48 hours of operation ahead and how forecasting information can be delivered to the system operator in a useful and actionable way.	Mark Ahlstrom May, 2010

The output of wind and solar power plants is subject to greater variability and uncertainty than conventional generation. This variability and uncertainty is due not to the generation technology, but to the implicit nature of the fuel sources (wind and sun) that are influenced by weather. Forecasting is one of the tools that can be used to address concerns and costs around this variability and uncertainty. The Task 2-1 report discusses operational and market system impacts, provides background on what can be realistically expected from VG power-output forecasting, and proposes recommendations to deploy forecasting systems into operational use.

The Task 2-1 report focuses on the operating time frame—from real time to the coming 48 hours. Forecasting of VG resources is important in all time frames, and there are many uses for longer-range forecasts from days and weeks (e.g., transmission outage planning and minimum generation issues) to years (e.g., integrated resource planning, where resource flexibility and ramping capabilities should be increasingly valued, and the generation mix—if not appropriately planned—can raise bigger challenges during the operating time frame). Such longer-term schedules are adjusted as they get closer to real time, and the critical operating impacts to BPS reliability tend to be closer to real time. Therefore, again in the interests of focus and expediency, this report primarily discusses the forecasting requirements for the coming 48 hours and particularly considers how forecasting information can be delivered to the system operator in a useful and actionable way.

Conclusions

- Aggregate forecast accuracy improves with the size of the region forecast, and aggregation across broad geographical regions can significantly reduce the uncertainty of output forecasts.
- Large system or market size and system flexibility improves the operator's ability to deal with variability.
- Methods for clear and efficient prioritization of renewable resources during curtailment conditions are important for both reliability and economics. For example, regional markets should evaluate adding negative curtailment pricing to their dispatch algorithms to encourage logical and efficient responses from all resources.
- VG power forecasts in multiple time frames are critical for maintaining both system reliability and economic operation.
- At any given time, the importance of the forecast to system reliability will depend on the operating state of the BPS.
- The accurate forecasting of ramp events potentially represents a significant challenge for power system reliability with respect to the integration of VG, although because the variability remains even when uncertainty is reduced, work toward improved forecasting must also be balanced with improvements in system operations and flexibility.

- The relative value of ramp forecasts will depend in part on the system posture. Uncertainty information surrounding the forecast can be provided in ways that best suit the needs of the system operator.
- Electrical (power, availability, curtailment) and meteorological data from wind and solar plants, delivered to the forecaster and system operator on a timely and reliable basis, are critical for forecast accuracy.

Key Findings and Recommendations

For the Industry

- Wind and solar plants require real-time meteorological and electrical data through SCADA systems using standard communication protocols for use in forecasting and system operation, including power, availability, curtailment, and meteorological data.
- Wind plant output forecasts, often several of them, should be adopted as standard system and market operation tools for economic operation and system reliability purposes. Multiple types of forecasts and forecast optimizations are practical and important.
  - Clarity around how a particular forecast will be used must be clearly defined for both the provider and user of a forecast product.
  - Given the value of incrementally better forecasts, system operators should consider a multiple-forecasting-provider model rather than using a single external or internal forecasting service.
  - A ramp forecast is possible and useful but may need to be optimized for a different use than the conventional power forecast. The “chance of ramp” indication is valuable even if it is not perfect. In fact, the complexity of weather events guarantees that ramp forecasts will not be perfect.
  - It may be beneficial to tune the wind power forecast to take into account the state of the power system. Morning load pickups and evening load drop-offs may require better knowledge of the likelihood of wind ramps and should be investigated by the system operator.
- How forecasts are used is what really matters.
  - Initial use of aggregate, regional, and individual wind plant forecasts by reliability coordinators in the control room is a logical first step.
  - Use of the forecast in unit commitment planning is very important. Appropriately clearing the day-ahead market with a combined load and wind power forecast (rather than ignoring the wind) will improve both the economics and reliability of system operation.
  - Probabilistic methods are increasingly important, and the uncertainty distributions around all forecasts (including but not limited to the VG power forecasts) should be addressed more explicitly. As a minimum, the use of a chance-of-ramp forecast probability should be used to identify whether or not additional reserves are needed.
- There are overwhelming benefits from adjusting operating rules and practices, and these adjustments may have more benefit to both reliability and economic operations than the forecasting alone.
  - Sub-hourly markets with sufficient liquidity, or the ability to otherwise dispatch generation closer to real time with sufficient flexibility, can be very effective in addressing the variability and uncertainty of VG.
  - Incorporating the VG power forecast into unit commitment is important for economical and reliable operation.
  - Negative price offers for resources should be included in markets that do not yet offer this capability to help maintain reliable and economical operation.

  - The benefits of larger balancing areas with fewer transmission constraints can be substantial. Resolving transmission constraints is critical because larger balancing areas lose many of the benefits associated with size if constraints are in play. Areas with sufficient transmission capacity are exploring how to achieve the benefits of larger areas through direct balancing area consolidation or through efforts at "virtual consolidation" where separate balancing areas work together on particular issues. Smaller areas, such as island systems, will have special challenges that require additional control. Larger operating areas with minimal transmission constraints and diverse VG assets should be capable of dealing with the expected levels of VG.

- Ongoing innovation is needed with both government and private industry involvement. Innovation is needed to continue to improve forecasting products. This requires multiple cooperating players:
  - Government R&D and forecasting centers for improved data systems, model development, and general operational weather deliverables;
  - A vibrant, competitive forecasting service community to assist in the R&D, applications, and services for business-augmented use of operating data with forecasting products;
  - Developers of system operating tools and methods, both in private companies and in the system operator organizations, to deal with the true variability and forecast probability distributions that are implicit to our real-world systems, system operators, and stakeholders.

For the Standards

The following recommendations were included in the original report. Many of these items have subsequently been addressed or reviewed by FERC Order 764 and ongoing standard development processes since the report was issued in 2010. Updated comments from the Task Lead are noted below in brackets but were not part of the original report or the report's approval process.

Table 4. IVGTF Recommended Standards Improvements

Standard	Definition	Recommendations
FAC-001	Facility Connection Requirements	The Transmission Owner's connection requirements for generation facilities (Section R2) should reflect the need for appropriate data from VG plants including power, availability, curtailment, etc. The standard may require a basic level of meteorological data from wind, solar, and other VG plants whose power output is influenced by local weather events. [For wind, this has been largely addressed with FERC Order 764 and grid codes.]
TOP-002	Normal Operations Planning	This standard may need to be updated to include a section about forecasting, identifying the data submitted by variable generators as the method of providing generation information to the Transmission Operators, and also recognizing forecasting as the best way to estimate generation, albeit subject to some unavoidable uncertainty due to the variability and complexity of weather conditions. [For

		wind, this has been largely addressed with FERC Order 764 and grid codes.]
TOP-006	Monitoring System Conditions	Requirement 1.1 could be interpreted as requiring availability information. Since availability information is useful for forecasting the output of variability of generation plants (like wind plants) with multiple turbines, this requirement should be reviewed to consider if the current language is sufficient. [FERC Order 764 includes the right for the system operator to obtain availability information (and other data) from wind plants if needed for forecasting.]
BAL-002	Disturbance Control Performance	The standard may need to be revised to include sudden changes in wind output as "credible contingencies" under the standard. This would ensure that these events are analyzed during reserve calculations. The applicable section of the standard is Requirement 3.1.
COM-002	Communication and Coordination	The standard may need to be revised to clarify the meaning of "voice and data links." To avoid problematic interpretations, the standard should specify that voice and data links are those identified in Interconnection Agreements or other governing agreements between the Transmission Operators and the variable generator.
IRO-005	Reliability Coordination – Current-Day Operations	This standard may need to be updated to include active monitoring of forecasting conditions such as weather fronts, icing, or high-wind conditions by the Reliability Coordinator. The active monitoring would ensure that the Reliability Coordinator is aware of conditions that may arise in the immediate future. This would create consistency with the purpose of the standard, which is: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."

In addition to the above recommendations, NERC Reliability Standards that address the reasonable and effective use of regional forecasts and local wind/solar facility forecasts should be encouraged and used to schedule VG.

Task 2-2: BA Communications

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Reliability Considerations for BA Communications with Increased Variable Generation	Address communications requirements between the variable renewable generation plant and the BA.	Bill Grant March, 2012

Task 2-2 addresses communications requirements between variable renewable generation plants and the associated BA. Increased variability will require a robust communication network between BAs and plant operators to ensure the grid continues to operate reliably. Improved forecasting accuracy and expanded backup generation facilities (i.e., natural gas plants) with expedient ramp rates can help to alleviate these disadvantages. However, in order for wind generation to provide power plant control capabilities, it must be visible to the system operator and able to respond to dispatch instructions during normal and emergency conditions. Accordingly, enhanced communication protocols will be needed to ensure wind resources can become a more significant part of the North American generation mix without compromising grid reliability.

Real-time communication capabilities for system operators will continue to play an instrumental role, especially during system restoration efforts that require increased coordination between a given Balancing Area and the Transmission System Operator (TSO). The TSO's inability to access up-to-date information on the output of VG resources has caused consequences such as those seen during an event in November 2006, when the European grid experienced power disruption to over 15 million households. It was determined that grid operators lacked the capability to communicate data for variable wind resources, most of which were reconnecting to the distribution system automatically (as system conditions allowed). The lack of real-time visibility of these resources ultimately counteracted the TSO's efforts to effectively balance the system.

Communication protocols used by wind plants and other VG can range from basic telephone calls and emails to different SCADA (supervisory control and data acquisition) systems. Currently, no industry-wide protocols have been established. This report explores some of the BA communication protocols used in North America, with a focus on the effectiveness of these protocols in the absence of conformity.

The Task 2-2 report details the current data and communications requirements for wind plants in ERCOT, NYISO, PJM, BPA, Hawaii, AESO, BC Hydro, and Hydro Quebec.

Key Findings and Recommendations

Communication Recommendations for Wind Resources

The Task 2-2 report discussed and identified a range of data that would enhance the reliability of the BES. Specific data and associated communication requirements identified are already required in developed markets. These data and communication capabilities should be provided to the BA by all generation operating in the BA that has an impact on the reliability of the BES. These are listed as follows:

- Net and gross MW and MVAR output
- Meteorological data (wind speed, wind direction, temperature, and barometric pressure)
- High- and low-sustained limit

- Normal and emergency ramp-rate capability
- Turbine availability
- Breaker status
- Modeling data (static information)
  - Tower height
  - Relay settings (including UFR settings)
  - Type of turbines
- Voice circuit
  - Available communication to plant operator
  - Communication to address real-time operational issues
- Set point and curtailment communication (to Balancing Areas)

Currently, most of these requirements are not applicable for a significant number of smaller wind farms (less than 75 MW) unless they are covered in the interconnection agreement or the market rules (if applicable). Generators connected to the distribution system usually do not have these data and communication requirements in their interconnection agreements either but can have a significant impact on the transmission system. Several smaller wind farms, regardless of the interconnection to the transmission system or the distribution system, can in aggregate have a significant impact on a specific area of the BES. For these reasons we make the following recommendation:

All generators 10 MW or greater within a BA regardless of interconnection point shall provide:

- Breaker status to the BA/TOP (FAC-001)
- Current MW and MVAR output (FAC-001)
- Voice circuit for communication of real-time instruction (COM-002)
  - Remote control of resources is adequate but should be capable of handling real-time operational issues.
- Coordination of relay settings, specifically under-frequency coordination (FAC-001)

The following should also be required for all generators 10 MW or greater within a BA regardless of interconnection point, if a significant impact has been identified in an interconnection study:

- Resource schedules with outage information (FAC-001)
- Meteorological data for forecasting (FAC-001)
- Availability (FAC-001)
- High- and low-sustained limit (FAC-001)
  - Include high-wind cutout
  - Temperature limitations
  - Any other operational restrictions

Recommendations for NERC Standards

In order to implement these changes, the following standards will have to be reviewed and updated:

- **FAC-001**: Transmission Operators would list their specific requirements not only for generation connected to the transmission system but also any generation in the footprint that is within the area that will impact the operation of the BA and BES.
- **COM-002**: Consider applying the standard to all generation down to 10 MW or greater. This will not only improve data communication but also require the Generator Operator to be available to address real-time operational issues. This can be accomplished with manned resources or remote control and monitoring of the facilities.
- **PRC-001**: Make Requirement 3 applicable to facilities 10 MW or greater. This will ensure that the necessary relay coordination has taken place to reduce the reliability impact of unexpected relay operation, specifically operation of under- and over-frequency relays. The generation should be set lower than the UFLS relays in the region to ensure generation tripping does not compound under-frequency operation similar to the European event.
- **TOP-001**: Under Requirement 3, require all generation facilities 10 MW or greater to comply with reliability directives from the Balancing Authority or the Transmission Operator. Under Requirement 7, all generation facilities of 10 MW or greater should provide notice to the Balancing Authority and the Transmission Operator before removing generation facilities from service to reduce the reliability impact to the system.
- **TOP-002-2b**: Under Requirement 3, require all generation facilities 10 MW or greater to provide their current, next-day, and seasonal operations with the host Balancing Authority and Transmission Provider. This will improve the reliability studies of the BES.
- **TOP-003-1**: For generation facilities 10 MW or greater, require outage coordination of generation facilities including telemetering equipment and voltage regulation equipment so that interconnected operations are coordinated between Balancing Authorities, Transmission Operators, and Reliability Coordinators.

These changes should be reviewed and implemented in the next review cycle. Adding these requirements to the functional requirements with audit oversight will ensure the operators have the tools necessary not only for normal operations but also for abnormal operations and system restoration.

Task 2-3: Ancillary Services and Balancing Authority Area Solutions to Integrating Variable Generation

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Ancillary Services and Balancing Authority Area Solutions to Integrating Variable Generation	Address communications requirements between the variable renewable generation plant and the Balancing Authority.	Jay Caspary March, 2011
	Study provisions of ancillary services from other jurisdictions, ACE sharing, or shorter scheduling intervals within and between Balancing Authority Areas to manage and spread the effects from variability of generation resources over a larger footprint.	
	Review existing and proposed standards.	

Task 2-3 addresses ancillary service requirements with VG. Balancing generation and demand with increasing levels of VG using traditional ancillary service products and operating practices could become a challenge for BAs. The BA must keep in mind the potential reliability considerations and variables involved. Enhanced tools, used daily to determine reserve operating capacities, can reduce uncertainty in maintaining generation-load balance under increased VG resources. Studies have shown that balancing VG over large geographic areas such as RTO regions increases diversity of wind resources, thereby reducing the aggregate variability of the generation output.

The objective of this task was to assess the need for ancillary services from both inside and outside existing BA Areas and to assess the need for changes in operating practices due to additional VG. The NERC Operating Committee approved the formation of this task team to study the consequences of enlarging existing BA Areas or participating in wider and multiple BA Area management. This multiple Balancing Authority Area management would include provisions of ancillary services from other jurisdictions, ACE sharing, or shorter scheduling intervals within and between BA Areas to manage and spread the effects from variability of generation resources over a larger footprint. In addition, existing and proposed standards were reviewed to determine their sufficiency in response to these evolving conditions. This report developed a survey of current Regional Entities' operations and methods, including application of their Renewable Portfolio Standards (RPSs). This assessment evaluates NERC'S Reliability Standards and includes recommendations that were deemed appropriate by the team.

The Task 2-3 report includes a survey that reviews the ways each Regional Entity addresses frequency response, regulation, and spinning and non-spinning reserves. The regulation footprint for maintaining balance between generation and load is defined by metered boundaries within a BA Area. Within the aggregate of all BAs, all generation and load within the interconnection is monitored and regulated for generation-load balance. As defined in BAL-005, each BA Area is required to have Automatic Generation Control (AGC) and to calculate Area Control Error (ACE) and deploy regulating reserve to balance resources and demand.

Key Findings and Recommendations

The objective of this report is to explore different practices and instill awareness of how BA Areas depend on short- and long-term planning and forecasting, complemented by sound Reliability Standards and efficient operating practices. BA Areas may cope with high variability in many ways. BA Areas with low penetration of

variable resources may rely predominantly on ancillary services packaged in a variety of specific products. In contrast, many BA Areas or regions with high penetration of variable resources have already developed broader regional solutions to maintaining energy balance.

The general observation, however, is that increased variability of generator output requires increased flexibility of dispatch operations. Therefore, the task force embarked on answering the following questions: What are the BA rules each entity most follow? Further, how will the existing 100-plus BAs operate in a homogenous way to address ancillary service requirements from VG?

Recommendation 1: Each region or reserve-sharing group should permit contingency reserve deployment under imbalance energy circumstances that are made more likely with the increasing penetration of renewables.

Recommendation 2: The task team recommends that the generator interconnection requirements be modified to require this dispatchable control capability to interface with the grid operator for all new VG resource developments.

Recommendation 3: Regional market operators and other grid-operating entities should develop the ability to consider transmission service by prioritizing variable resources when allocating curtailment responsibility to variable output resources during reliability-limited operating conditions.

Table 5. Recommendation to Reliability Standards

Standard	Definition	Recommendations
BAL-001-0.1a	Real Power Balancing Control Performance	Increase BA collaboration to reduce cost overall and to make it valuable for integration of VG.
BAL-002-0	Disturbance Control Performance	The standard drafting team should consider if contingency reserves can be used to meet DCS requirements for wind-related events. Reserve calculation procedures should be updated to take into account variable energy resource events including ramping events that are much slower than the instantaneous contingency events caused by conventional generators and transmission failures. This could impact recommendations for Contingency Reserve Policies, DCS, DCS response time, and DCS recovery time.
		Alternatively, the current BAL-002 and DCS do not apply to variable energy resource events because they are too slow. There is no need to change BAL-002 due to variable energy resource integration. Balancing Authorities would need to deal with the risk of tail events with their own resources—or with different resources than the current DCS resources. Ultimately, it would be more efficient to mitigate the risk of rare tail

		events by using pooled reserves, especially in high-penetration scenarios.
		Action: **IVGTF2-3 should collaborate with the standards drafting team to establish another requirement to accommodate VERs and their tail events.**
IRO-005-3-1a	Reliability Coordination — Current-Day Operations	A NERC standard is required to communicate VG derates due to turbine outage conditions and plans. Currently issues may arise if part of a wind plant is out of service and operators are not aware of the number of turbines unavailable and duration of the forced or planned outage.
TOP-002-2&A	Normal Operations Planning	The standard should be enhanced to provide guidance on incorporation of variable energy resource events into the planning process.
TOP-006-1&2	Monitoring System Conditions	Expand R4 to require similar information and prediction of VG output: R4. Each Transmission Operator and Balancing Authority shall have information including weather forecasts, and past load and variable generation patterns are available to predict the system's near-term load and variable generation pattern.

Task 2-4: Operating Practices Procedures and Tools

Task Summaries

Special Assessment Report	Objective	Task Lead and Approved Date
Operating Practices Procedures and Tools	Discuss VG impact on power system operations.	Brendan Kirby March, 2011
	Discuss the need to modify operating practices, procedures, and tools.	
	Address the impacts on commitment and/or dispatch along with reserve management practices.	

Key Findings and Recommendations

NERC Standards

One of the goals of Task 2-4 is to evaluate needed changes to NERC's Reliability Standards. Several NERC Reliability Standards may need to be updated. The following standards require enhancement:

- **BAL-002** (Disturbance Control Performance) – This standard may need to be revised to include sudden changes in wind output as "credible contingencies." This would ensure that these events are analyzed during capacity reserve margin calculations. The applicable section of the standard is Requirement 3-1. Additionally, changes to this standard may need to be addressed with various reserve-sharing groups, many of which have differing rules regarding contingencies.
- **BAL-005 R11** (Automatic Generation Control) – This standard may need to be updated to include the various types of ramp rates that a BA may need to use in the Scheduled Interchange values to calculate ACE. Controlled and uncontrolled ramp rates may need to be included in the analysis since both types can be encountered by VG.
- **COM-002** (Communication and Coordination) – The standard may need to be revised to clarify the meaning of "voice and data links." To avoid problematic interpretations, the standard should specify that voice and data links are those identified in Interconnection Agreements or other governing agreements between the Transmission Operators and the variable generator.
- **EOP-002 R6 (Capacity and Energy Emergencies)** – This standard may need to be updated to reflect curtailment capabilities of various types of generation as one of the possible remedies available to BAs. This would ensure that a BA has examined various types of remedies that are available when experiencing problems meeting the Control Performance and Disturbance Control standards.
- **IRO-004** (Reliability Coordination – Operations Planning) – This standard may need to be updated to reflect forecasting information available to VG that is to be made available for next-day studies. Currently, the standard indicates that parties "shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known Interchange Transactions." Forecasting of VG could be added to the list to provide an accurate day-ahead study.
- **IRO-005** (Reliability Coordination – Current-Day Operations) – This standard may need to be updated to include active monitoring of forecasting conditions such as weather fronts, icing, and high wind conditions by the Reliability Coordinator. The active monitoring would ensure that the Reliability Coordinator is aware of conditions that may arise in the immediate future. This would create consistency with the purpose of the standard, which is: "The Reliability Coordinator must be continuously aware of conditions

within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."

- **TOP-002** (Normal Operations Planning) – This standard may need to be updated to include a section about forecasting that identifies the data submitted by variable generators as the method of providing generation information to the Transmission Operators, and also recognizes forecasting as the best way to estimate generation, albeit subject to some unavoidable uncertainty due to the variability and complexity of weather conditions. This would assist in system operations, especially in day-ahead or hour-ahead operations.
- **TOP-006** (Monitoring System Conditions) – Requirement 5 of this standard discusses the use of "monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action." This standard may need to be revised to include specific tools, such as (1) input from a forecaster, or (2) real-time data from wind and solar plants (e.g., meteorological towers, sonic detection and ranging (SODAR), and real-time turbine telemetry).

In addition, NERC Reliability Standards that address the reasonable and effective use of regional forecasts and local wind or solar facility forecasts should be encouraged and used to schedule VG to assist in accurate system operation.

Other Conclusions and Recommendations

Improved operating practices, procedures, and tools can help reliably integrate VG into the power system as well as improve the reliability of the power system in the absence of VG. Reliability resources such as flexible generation and responsive load are finite. Operating practices, procedures, and tools that reduce variability and uncertainty while maximizing the effective use of limited responsive resources improve reliability and facilitate VG integration.

Variability and uncertainty can be reduced through aggregation. Larger aggregations of wind and solar generation are proportionately less variable. Forecast accuracy is also improved for larger wind and solar aggregations. Net variability is reduced when VERs are aggregated with load, and it is net variability that must be balanced to maintain reliability. The pool of flexible resources (generators and responsive load) increases as the size of the BA is increased. Balancing should be conducted over the largest geographic area possible, either through consolidating smaller BAs or through coordinated operations.

Wind and solar forecasts become more accurate closer to real time. Unit commitment and economic dispatch should be performed as close to real time as possible. Five-minute economic scheduling of generation is common in North America. The IVGTF suggests that those Balancing Areas who face significant integration of variable resources consider studying the benefits of sub-hourly scheduling to manage the integration of VG. Depending on the current or projected BA system characteristics, assuming sufficient transmission is available, there may be benefits to intra-hour interchange scheduling, in the form of reduced ancillary services, and more flexibility and ability to manage the variability while still meeting the requirements of NERC's Reliability Standards.

Conclusions:

- Increasing system variability increases the importance for operators to have visibility of system conditions, access to tools to resolve conditions, and clear rules on when to implement those tools.
- Aggregate forecast accuracy improves with the size of the forecast region.

- Aggregation across broad geographical regions significantly reduces output variability and associated operating reserve requirements. In general, the aggregate uncertainty should also be mitigated by such aggregation, but the uncertainty and impacts from rare events may require more consideration.
- Large system or market size and flexibility improve the ability to deal with variability.
- Methods to ensure efficient prioritization of renewable resources during curtailment conditions are important for both reliability and economics. For example, regional markets should evaluate adding negative curtailment pricing to their dispatch algorithms to encourage logical and efficient responses from all resources.
- Electrical (power, availability, curtailment) and meteorological data from wind and solar plants, delivered to the forecaster and system operator on a timely and reliable basis, is critical for forecast accuracy and reliable operations.

Recommendations:

- Wind and solar plants should have the capability to send and receive real-time data (meteorological and electrical) through SCADA systems using standard communication protocols for use in forecasting and system operation.
- Wind plant output forecasts, often several of them, should be adopted as standard system and market operation tools for economic operation and system reliability purposes. Ramp forecasts as well as hourly energy forecasts should be considered.
- NERC Regions should consider what control capabilities should be required for new VERs to ensure reliability. Procedures should be developed that limit the use of VER control capabilities to situations where it is required to maintain reliability or when accepting the energy results in excessive costs.
- Interconnection requirements for all generation technologies (VER and conventional) need to be designed for anticipated rather than existing conditions, considering aggregate impacts and effects of displacing conventional generation. Interconnection requirements should address control capability, ride-through, inertial response, voltage regulation, etc. It is difficult to modify requirements on existing facilities after the fact.
- Tools including visualization are needed for system operators to process and present the wide range of information (aggregate forecasts, status of VERs, ramping capabilities, geographic coverage of ACE sharing, etc.) to the system operator.
- Changes to operating rules and practices are critical:
  - Sub-hourly markets with sufficient liquidity, or the ability to otherwise dispatch generation closer to real time with sufficient flexibility, can be effective in addressing the variability and uncertainty of VG.
  - Incorporating the VG power forecast into unit commitment and dispatch procedures is important for economical and reliable operation.
  - More frequent unit commitment can use updated forecasts of VERs and load.
  - Consider adjusting reserve requirements based on forecast VER output levels. This would allow the reserves to capture the fact that the volatility of wind output is different for different output levels.
  - Mechanisms to incent dispatch behavior consistent with system needs are required. For example, the interaction between variable resources supported by tax credits and renewable energy credits or monetized environmental benefits and a significant proportion of base load generation with significant minimum generation requirements suggests that the capability to capture negative price offers for resources may be needed to clear markets.

- The benefits of larger Balancing Areas with fewer transmission constraints can be substantial. Resolving transmission constraints is critical because larger Balancing Areas lose many of the benefits associated with size if constraints are in play. Different parts of the country are exploring how to achieve the benefits of larger areas through direct Balancing Area consolidation or through efforts at "virtual consolidation" where separate balancing areas work together on particular issues. Smaller areas, such as island systems, will have special challenges that require additional control. Larger operating areas, with minimal transmission constraints and diverse VG assets, should be capable of dealing with the expected levels of VG.
- Task 2-4 recommendations have suggested potential enhancements for consideration by the standards authorization drafting groups.

Conclusions and Recommendations

This report summarizes the findings from the total IVGTF multi-task effort. Findings and recommendations provide a reference manual of best practices for planners, operators, regulators, developers, and investors dealing with the challenges and opportunities offered by VG. Specific recommendations for standards development are included. This report also highlights areas that require further study and development; some are technological and others are institutional in nature.

The task reports note that the growth of wind and solar generation is not happening in isolation. Variability and uncertainty from VG must be considered in the context of the variability and uncertainty of load as well as the probability of conventional generation and transmission contingencies. Tools, standards, and operating practices must address the aggregate power system to ensure reliability at least cost.

While there are numerous recommendations for greater specificity in standards and interconnection requirements, as well as improvements in operator analysis tools and operating practices, there are also acknowledgements of developments that will likely ease VG integration challenges. The NERC *2013 Long-Term Reliability Assessment* notes that over the next 10 years there will likely be a shift toward a dramatically different resource mix with greater reliance on natural gas and renewable generation. NERC also expects about 71 GW of fossil-fired generation (primarily coal) to retire by 2022. While this shift to gas-fired generation raises fuel diversity concerns, it will also likely result in a conventional generation fleet with greater flexibility that is better able to accommodate the increased variability and uncertainty of VG.

DR is expected to grow as well, further enhancing the system's flexibility. NERC-wide, demand-side management (DSM) is projected to total roughly 80,000 MW by 2022 (or about 7 percent of the on-peak resource portfolio), offsetting approximately six years of peak demand growth.

Another positive trend is the growth in transmission to accommodate new and distant resources. As recently as five years ago, transmission was being constructed at a rate of about 1,000 circuit miles per year. In the last five years, over 2,300 circuit miles were constructed per year, more than doubling actual builds in the previous five years. With the current plans in place, that rate is expected to increase to 3,600 miles per year over the next five years. NERC-wide, almost a quarter of new transmission is specifically linked to the integration of renewable generation.

The IVGTF effort should be an ongoing process that incorporates the greater operating experience that continues to be gained and that reflects the advances in equipment and analysis tools. As it works through NERC's process for reviewing and developing standards, IVGTF recommendations for standards requirements should be considered promptly by standard drafting teams, entities, and by NERC's special assessments. In some cases, standards have already moved forward during the development of the IVGTF reports, sometimes in agreement with the IVGTF recommendations and sometimes not, and the IVGTF recommendations should be considered in light of these dynamic changes.

NERC staff will continue to monitor the progress of the IVGTF recommendations and recommends disbanding the IVGTF and delegating this continuing effort to NERC reliability and special assessment reports. With the commissioning of the Essential Reliability Services Task Force (ERSTF), which carries out actions for enhancing system reliability due to changes facing the BPS, NERC staff recommends transitioning related IVGTF work on recommendations to the ERSTF work plans and activities.[12]

[12] NERC commissioned the ERSTF to study, identify, and analyze the planning and operational changes that may impact BPS reliability. This task force is jointly commissioned between NERC's Planning and Operating Committees. More information on the ERSTF work plan and activities can be found at the ERSTF Webpage.

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Appendix I

Transition Plan on IVGTF Recommendations	
Task 1-1 Standard Models for Variable Generation	
Transition Category	Planning –Technical Guidelines
Recommendation: The NERC standard FAC-001 should be expanded to clearly cover modeling requirements during the coordinated joint study phase of the Facility connection process. Simple generic models of variable generation may be adequate for the IES phase and more detailed models may be needed for the IFS phase. Validation of the simple and detailed model parameters may be needed during commissioning. **Response:** Mandating how system impact and facilities studies are completed is not appropriate and should not be part of a Reliability Standard. This level of prescriptiveness goes against the results-based approach for Standards. FAC-001 was just revised and the technical experts on the SDT and stakeholders did not agree that this level of prescriptiveness was appropriate. Therefore, no action is needed in NERC standards; this is a comment for utilities and ISOs to consider for interconnection agreements.	
Transition Category	Planning –Technical Guidelines
Recommendation: MOD-011 and MOD-012[13] Apply VG as a source of generation. **Response:** The proposed modifications generally align with the DG SDT's position on MOD-032. The DG SDT recommends leaving the existing standard language as is, but for NERC to publish guidance documents on how to best model dispersed generating resources. In particular, the SDT suggested that the guidance should "…require modeling requirements for each type of dispersed generation resource within a facility and aggregate model for each reasonable aggregation point," similar to the additional language being proposed by the IVGTF to be added to attachment 1. Note that while one or two individuals who have participated in some of the DG SDT meetings have argued that detailed models should be provided by DG resource owners of the entire site all the way down to the individual resources (versus providing an aggregate model/equivalent unit), this was generally dismissed by the DG SDT. It was the SDT consensus that an aggregate model/equivalent unit was sufficient and we currently agree with this position. NERC will publish guidance documents on how to best model dispersed generating resources. **Recommendation: MOD-013:** Include an explicit statement to cover VG. **Response:** Solar thermal dynamic models will be very similar to a typical fossil generating unit; while the fuel source is different, the steam turbine and generator components will be similar. For discussion, large-scale battery storage is a possible addition to this list. Our current assumption is that while battery storage technologies are diverse, their inverter-based interface will generally be similar to PV systems, so perhaps they can be covered in a way that is comparable to photovoltaic systems.	
Transition Category	No Action
MOD-024-1 Recommendation: Require wind units' total gross capability methods as the sum of the nameplate rating of all individual units. **Response:** Since losses due to the collection system are inherent to the design of a wind or solar site (vs. auxiliary equipment that could theoretically remain offline during the testing), no specific instructions should be needed to ensure that these are accounted for during testing. However, there is a section in attachment 1 (page 15 item 3.7) for the entity to provide the GSU losses if testing values were taken on the high side of the GSU. Assuming most entities will perform this testing at an aggregate level rather than at an individual unit basis, if collection system losses were	

[13] MOD-011 Standard is supported by MOD-025-2 Attachment 1 Item 2.1.2. http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-025-2&title=Verification_and_Data_Reporting_of_Generator_Real_and_Reactive_Power_Capability_and_Synchronous_Condenser_Reactive_Power_Capability

deemed useful information to be provided to the Transmission Planner (and in fact, it might not be relevant data for the TP), this would be the location for it. Task leads suggest a 3.7.1 bullet point stating something along these lines: "For variable generating units such as wind or solar that utilize a collection system designed for aggregating the generation to a common point of connection, record the collection system losses (real or reactive)." The Drafting Team for Project 2014-01, in light of the revised BES definition approved by FERC in 2014, approached revisions to the standards with a general intent to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed generation resources, where the status quo does not create a reliability gap.

Transition Category	Standards Review and/or Standard Authorization Request (SAR)

MOD-026-1 Recommendation: Standards are tailored explicitly to deal with synchronous-type generators, and items need to be clarified in these standards as they pertain to VG, particularly for:

- Unit/plant size for validation
- Validation of various technologies in a single plant
- Validation of different control layers
- Modeling and model validation
- Future functionality
- Modeling of protection
- Issues related to the fuel source for VG
- Model revalidation

Response: MOD-025-2 already does require confirmation of reactive capability of variable generation such as wind and PV solar. Section 2.1.2 of attachment 1 states the following:

- Verify variable generating units, such as wind, solar, and run-of-river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.
- Typical wind and solar sites have installed reactive capabilities in order to ensure they can meet the power factor requirements that are usually listed within their interconnection agreements. Verification that a site can meet its power factor requirements (often 95% lag and lead) would remove the variable nature of the generation from the reactive power verification testing. The 90% of wind turbines/solar inverters online requirement should be maintained for this testing.

Project 2007-09 addressed revisions to a number of standards in the MOD and PRC families. As a result of that project, MOD-025-2 was developed and is subject to future enforcement.

MOD-025-2 R1 states, "[e]ach Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: . . . [v]erify the Real Power capability of its generating units in accordance with Attachment 1." Section 2.1.2 of Attachment 1 requires the entity to: "[v]erify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications."

The recommendation appears to be adequately addressed through the combined requirements of MOD-025-2, Attachment 1, Item 2.1.2; MOD-026-1; and MOD-027-1 (to include footnote 3b). Transmission Planners will have access to the information obtained as a result of MOD-025-2, which will then be used in compliance with MOD-026-1 and MOD-027, thereby ensuring variable generation is consistently and appropriately accounted for through the complementary design of the MOD standards.

MOD-025-2, which is subject to future enforcement, includes as R1 the requirement, "[e]ach Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: . . . [v]erify the Real Power capability of its generating units in accordance with Attachment 1." Section 2.1.2 of Attachment 1 requires the entity to: "[v]erify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications."

However, the current DGR SDT position (from currently posted version of the White Paper) is as follows:

4.7.5 MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability. The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. This standard is appropriate for and includes specific provisions for dispersed generation resources to ensure changes in capabilities are reported. Therefore, the SDT is further evaluating whether to revise the applicability of the standard to align the language with the revised BES definition.

MOD-027 includes footnote 3b, which clarifies, "Turbine/governor and load control or active power/frequency control: . . . Active power/frequency control applies to inverter connected generators (often found at variable energy plants)." Further, the applicability of MOD-026-1 and MOD-027 has been designed to capture approximately 80% of available generation; therefore, facilities are subject to the requirements if those facilities are included in the guidelines.

OD-025-1 Recommendation: Clarification may be needed. Namely, VG reactive capability of the "power plant" is not entirely inherent in the individual generating units regarding how the total reactive capability of the power plant is defined.

Task 1-2 Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning	
Transition Category	Planning –Technical Guidelines

Recommendations:

- Additional research to equate traditional reliability targets (such as a LOLE of 0.1day/year) to alternative metrics.
- LOLP, LOLE, or other related metrics should be used to calculate generation adequacy and capacity contributions of VG.
- More widely adopted energy-related reliability metrics and targets as the share of variable generation increases in the power system and recommend comparisons of results based on these alternative metrics.
- Planning reserve margin, calculated as a percentage of system peak, will become less meaningful with large penetrations of variable generation. Planning reserve margin levels should be periodically benchmarked with, or derived from, an LOLP or related approach to resource adequacy to ensure the account for any changes.
- Alternative approaches and assumptions regarding the treatment of interconnected systems should be transparent to the analysis.

- Development of one or more common approaches for handling the impact of interconnected systems in the reliability assessments.
- Simplified approaches should be benchmarked and calibrated to the rigorous ELCC calculations to ensure the validity of the approximation.
- The Ramp Response characteristic includes the rate of ramping required from flexible resources and the predictability of the ramp.

Transition Category	Data Collection

Recommendation: NERC should design and implement a way to collect high-quality variable generation data that would help inform calculations of capacity value.

Transition Category	NERC Reliability Assessments and External Coordination Activity

Recommendations:

- NERC should request that government agencies like the DOE, working with NOAA/NCAR, develop annual high-resolution, modeled wind and solar power data on 10-minute time scales and 2 km geographic grids.
- NERC should facilitate the dissemination of information about how LOLP-related reliability and adequacy calculations perform and what they measure.

Task 1-3 Interconnection Requirements for Variable Generation

Transition Category	Standards Review and/or SAR

Reactive Power and Voltage Control

Recommendation: NERC should consider revisions to FAC-001 expanding R.2.1.3 or create an appendix stating that interconnection standards for reactive power must cover specifications for minimum static and dynamic reactive power requirements at full power and at partial power, and how terminal voltage should affect the power factor or reactive range requirement. NERC should promote greater uniformity and clarity of reactive power requirements contained in connection standards that Transmission Operators have issued pursuant to FAC-001. NERC, FERC, and other applicable regional standards should be reconciled.

Response: VAR-001-4 R4 and R5 specifically call out "AVR" in the language. "AVR" is a term specific to conventional generation technology using synchronous machines with closed-loop voltage control executed by an exciter at each generator. "AVR" does not refer to the plant-level closed-loop voltage control provided by wind and solar plants. Wind and solar plants have the capability to regulate voltage and follow voltage schedules per the VAR-001 standards using a "plant-level volt/var controller." If "AVR" alone is used in the standard(s), it covers synchronous generation technology only and inherently neglects and could be interpreted to exempt wind and solar technologies from regulating voltage. There is also precedent in other existing NERC standards (such as MOD-026 and MOD-027) to specifically call out appropriate terminology for BES-connected wind and solar facilities to be sure these technologies are appropriately captured for the standard's applicability. The Task 1-3 team strongly believes that if AVR terminology is used in the standard at all, it should be revised to say "AVR or plant-level volt/var controller" to appropriately capture all generation technologies. The team recommends a white paper on the relationship between dynamic var capability and grid reliability to support a standard development activity.

Recommendation: NERC should consider revisions to VAR-001 standards to include the term "plant-level volt/var controller" (in addition to "AVR"), which is more appropriate for variable generation.

Response: VAR-001-4 R4 and R5 specifically call out "AVR" in the language. "AVR" is a term specific to conventional generation technology using synchronous machines with closed-loop voltage control executed by an exciter at each generator. "AVR" does not refer to the plant-level closed-loop voltage control provided by wind and solar plants. Wind and solar plants have the capability to regulate voltage and follow voltage schedules per the VAR-001 standards using a "plant-level volt/var controller." If "AVR" alone is used in the standard(s), it covers synchronous generation technology only and inherently neglects and could be interpreted to exempt wind and solar technologies from

regulating voltage. There is also precedent in other existing NERC standards (such as MOD-026 and MOD-027) to specifically call out appropriate terminology for BES-connected wind and solar facilities to be sure these technologies are appropriately captured for the standard's applicability. The Task 1-3 team strongly believes that if AVR terminology is used in the standard at all, it should be revised to say "AVR or plant-level volt/var controller" to appropriately capture all generation technologies.

Recommendation: NERC should consider initiating a Standards Authorization Request (SAR) to establish minimum reactive power capability standards for interconnection of all generators, and provide clear definitions of acceptable control performance.

Response: NERC may initiate a SAR in order to determine industry need.

Recommendation: Applicability: Generator interconnection requirement for reactive power should be clearly established for all generator technologies. NERC should consider giving transmission planners some discretion to establish variance based on the characteristics of their transmission systems and the sizes of the generators.

Recommendation: Specification of Reactive Range: The reactive range requirement should be defined over the full output range, and it should be applicable at the point of connection.

Recommendation: Impact of System Voltage on Reactive Power Capability: It should be recognized that system voltage level affects a generating plant's ability to deliver reactive power to the grid and the power system's requirement for reactive support.

Recommendation: Specification of Dynamic Reactive Capability: The standard should clearly define what is meant by "Dynamic" Reactive Capability by specifying the portion of the reactive power capability that is expected to be dynamic. A prospective standard should specify the minimum performance characteristic of the response in terms of response time, granularity (maximum step size), and repeatability (close-open-close cycling capability).

Recommendation: Definition of Control Performance – Expected volt/var control performance should be specified, including minimum control response time for voltage control, power factor control, and reactive power control. An interim period for the application of precisely defined control capabilities should be considered.

Recommendation: Effect of Generator Synchronization on System Voltage: Synchronization of generators to the grid should not cause excessive dynamic or steady-state voltage change at the point of connection. A 2 % limit may be considered as a baseline.

Recommendation: Special Considerations: NERC should investigate whether transmission operators can, under some conditions, allow variable generating plants to operate normally or temporarily at an active power level where dynamic reactive capability is limited or zero.

Recommendation: Technical Alternatives for Meeting Reactive Power Capability – The reactive power requirements should be applicable at the point of interconnection.

Recommendation: Commissioning tests – Commissioning tests, which are part of the interconnection process, often include a test to demonstrate plant compliance with reactive power capability requirements.

Transition Category	NERC Staff – External Coordination Activity

Performance During and After Disturbances Recommendations

1. The scope of PRC-024-1 should be broadened to cover smaller plant sizes. The current proposal of 75 MVA will miss many variable generator facilities that could impact the BES. It is suggested that the scope be broadened to cover all projects under a Large Generator Interconnection Agreement.
2. Or extend the scope to any project greater than 10 MW in order to provide coverage for plants not included under IEEE 1547.

Industry should decide the appropriate threshold (10 vs. 20 MW or MVA) as Regional Entity differences may be justified. Applicability should depend on total plant rating and should not be based on individual unit size. The BES definition describes facilities that are included in, and excluded from, the BES. If it is determined that a facility (or aggregation of units) impacts BES reliability, that facility will be accounted for through the BES inclusion process.

Standards for Manufactured Equipment Recommendation

Current solar PV inverters designed to comply with IEEE 1547 are required to provide anti-islanding capability and disconnection requirements that are not compatible with the fault ride-through requirements recommended here. Although individual inverters may have capacities on the order of 500 kW, utility-scale PV plants may have hundreds of these units and hence have a plant capacity of upwards of 100 MW. Furthermore, the inverters are listed at UL-1741, which is based on the requirements of IEEE 1547. This report recommends that new standards are proposed for utility-scale PV plants in order to drive the industry toward the adoption of new inverter specifications, testing, and certification.

Response: The team recommends that NERC keep track of the growth of variable generation that falls outside the NERC BES definition.

NERC should establish a coordination mechanism with IEEE Standard 1547 to ensure that BPS reliability needs are factored into the revision efforts of future DER interconnection standards. To date, BPS stakeholders have participated only sporadically in the IEEE Standard 1547 process. NERC should also encourage some BES reliability experts from utilities and ISOs to participate with the IEEE 1547 standard drafting process.

Transition Category	No Action

Recommendation: PRC-024 should clearly define performance requirements for unbalanced and balanced faults. The specification of voltage magnitude should define what voltage metric is applicable.

Transition Category	Standards Review and/or SAR

Disturbance Ride-Through Group

Recommendation: Voltage disturbance performance requirements, particularly high-voltage ride-through, should use the severity-cumulative duration form of specification to avoid unnecessary increase of VER plant costs to meet voltage disturbance durations that will never occur in practice.

Recommendation: Ride-through plots should be provided that specify both high- and low-voltage ride-through requirements. It is recommended that the zero-voltage ride-through should be equal to the three-phase fault-clearing time on the network. The zero-voltage ride-through is up to 9 cycles but may be less depending on the clearing time. This should be made explicit in any requirement.

Recommendation: Transmission-interconnected VER should not have any active anti-islanding functions enabled unless these functions are properly coordinated with all applicable stakeholders so that the functions do not detract from bulk transmission system transient or dynamic stability.

Recommendation: It is not suggested that a NERC-wide requirement be mandated for riding through a rate-of-frequency change. If a standard is desired by individual operators, a rate-of-change ride-through requirement of 2.5 Hz/s appears adequate. (This rate of frequency change is stipulated in the current draft of PRC-024). There may be some Regional Entity differences where at least 4.0 Hz/s is required.

Recommendation: Disturbance performance requirements, including PRC-024, should indicate the maximum level of transmission contingency (e.g., N-1-1) for which a plant should be required to ride through.

Response: PRC-024 needs a standards review.

Recommendation: Disturbance performance requirements, such as PRC-024, should clearly define any requirement for repeated disturbances.

Response: The NERC TPL-001-4 standard requires N-1-1 (P6 two overlapping singles) to be studied with system adjustments allowed. However, the time duration between the singles is not clearly defined: it could be 5 minutes or 30 minutes, for example, which has an impact on equipment ride-through capability.

Recommendation: PRC-024 should define the performance required during and after disturbances and should make clear and unambiguous statements as to what remaining “connected” entails. It is not recommended that active power be required during a voltage disturbance unless there is a reliability concern. The sourcing of reactive power during a severe fault should instead be given priority over real power delivery, and the magnitude of reactive power should be consistent with pre-fault reactive power capability. The capability to supply reactive current during a fault varies with technology and product offerings, and so a market to incentivize, but not require, the increased sourcing of reactive current during a voltage dip is recommended.

Transition Category	Planning – Technical Guidelines

Power Recovery after Blackout Recommendation: Recovery after Blackout: It is reasonable to clarify the restart expectations of a generator facility following a disturbance. In some cases, the Transmission Operator provides a signal to the facility that prohibits automatic restarting after a severe grid event. FAC-001 could be modified to include a facility connection requirement to address generator facility restarting.

Response: EOP-008 already covers system restoration, and interconnection agreements cover restarting of generating facilities after faults on the system or a blackout. There is no need or technical basis for FAC-001 to be revised. The Task 1-3 team recommends that NERC provide some technical guidance for industry.

Transition Category	Planning – Technical Guidelines

Recommendation to Require Capability to Limit Rate of Increase of Power Output: Variable generation plants should be required to have the capability to limit the rate of power increase. This type of up-ramp rate control capability has been required in some other systems. This function should include the ability to be enabled and disabled by instruction from the Transmission Operator, Balancing Authority, or Reliability Coordinator.

Recommendation: Plants must be able to accept commands to enable pre-selected ramp-rate limits. Plants should be designed with recognition that ramp-rate limits should not be required under all operating conditions. It should not be required that variable generation plants limit power decreases due to declines in wind speed or solar irradiation (i.e., down-ramp-rate limits). However, limits on decreases in power output due to other reasons, including curtailment commands, shut-down sequences, and responses to market conditions, can be reasonably required.

Response: The team recommends NERC, through its Planning Committee and the System Analysis and Modeling Subcommittee (SAMS), to provide a technical guideline document for the industry.

Transition Category	Planning – Technical Guidelines

Recommendation: Encourage or mandate reduction of active power in response to high frequencies: Variable generation plants should be encouraged to provide over-frequency droop response of similar character to that of other synchronous machine governors.

Recommendation: Consider requiring the capability to provide increase of active power for low frequencies: Variable generation plants should not be required to provide governor-like frequency response for low frequency under normal operating conditions. This is consistent with any conventional power plant operating at full throttle output (i.e., valves wide open). However, encouraging VGs to have the capability to provide this response, and then establish rules and possibly compensation for when such controls would be enabled, could be considered. This presumably would be a rare occurrence, as the economic penalty associated with enabling these controls is high.

Recommendation: Consider requiring inertial response in near future: With the exception of Hydro-Québec, inertial response characteristics have not been specified in grid codes or interconnection requirements for wind plants. Furthermore, language describing this functionality in technology-neutral terms and subject to the physical reality of variable generation facilities is not presently available. Requiring this function in the future as the technology matures and as grid operators and reliability organizations learn more about the need for inertial response characteristics from wind plants should be evaluated further. However, incremental costs should be carefully weighed against alternatives on both the supply and demand side for providing this important reliability service.

Response: ERSTF *Measures Framework* report will consider some of these concerns, and the team, along with the IVGTF leads, recommends that NERC (RAPA-RISA) write a technical guideline on frequency response.

Transition Category	Planning – Technical Guidelines

Recommendation on Harmonics and Subsynchronous Interaction: There is no need for NERC to develop interconnection criteria related to SSR/SSI or harmonics at this time. However, it would be prudent for transmission owners and grid operators to: 1) Consider design study reports that assess the harmonic performance of all wind and solar plants, and 2) Until better understanding of the control interactions issue is gained, consider design study reports

that assess the risk, and if necessary mitigation, of wind and solar plants located near series-compensated transmission lines or HVDC terminals.

Transition Category	No Action

Recommendations for Models for Facility Interconnection Studies

Accurate models are required for all generator facilities that are connected to or are planning to connect to the BES (100 kV and higher) regardless of size. Ongoing model revalidation is currently covered by:

- MOD-024-1: Verification of Generator Gross and Net Real Power Capability
- MOD-025-1: Verification of Generator Gross and Net Reactive Power Capability
- MOD-026-1: Verification of Models and Data for Generator Excitation System Functions
- MOD-027-1: Verification of Models and Data for Turbine/Governor and Load Control

The ongoing detailed model validation may evolve to cover generator units or generator facilities 75 MVA or larger. This breakpoint covers at least 80 percent of the currently installed generation in North America and matches the NERC Statement of Compliance Registry Criteria, which is approved by FERC.

Response: This is the current DGR SDT position from the currently posted version of the white paper "4.7.3 MOD-024-1 –Verification of Generation Gross and Net Real Power Capability."

Transition Category	Planning – Technical Guidelines

Recommendation: Summary of Facility Connection Model Grid Code Requirements: Several key features could be recommended for adoption by Transmission Owners.

- Preliminary model data may be used for the initial feasibility study of a variable generator interconnection project.
- The best model available shall be used for the final System Impact Study or Facilities Study. These models can be user-written and require nondisclosure agreements.
- The detailed dynamic model must be accurate over the frequency range of 0.1 to 5 Hz. Time constants in the model should not be less than 5 ms.
- The detailed dynamics model must have been validated against a physical or type test.
- Verification of detailed model performance should be confirmed during commissioning to the extent possible. The following tests shall be performed: 1) primary/secondary voltage control, 2) low-voltage and high-voltage ride-through, 3) power factor/reactive power capability, 4) Power Ramping and Power Curtailment.
- Verification of the non-proprietary model accuracy may be performed by simulation tests compared with the detailed model performance.
- At the end of the commissioning tests, the Generator Owner shall provide a verified detailed model and a non-proprietary model, ideally in IEEE, IEC, or other approved format, for ongoing Regional Entity studies such as TPL-001.

Response: IVGTF T1-3 response: There is minimal support to make FAC-001 prescriptive. The above recommendations can be documented in a technical guidance document for industry.

Transition Category	Planning – Technical Guidelines

Communications between Variable Generation Plants and Grid Operators Recommendation: The Task 1-3 project team recommends that the basic requirements for communications and control between grid operators and variable generation plants be based on existing policy for conventional generators.

- Variable generation plants should send a minimum set of monitoring data to the grid operation via the grid's SCADA network.
- Variable generation plants should receive and execute command signals (power limit, voltage schedule, ramp-rate limit, etc.) sent from the grid operator via the SCADA network.

- Variable generation plants should have trained on-call plant operators who can receive calls from the grid operator 24/7 and immediately execute verbal commands. The plant operators would not need to be located at the plant provided they have secure remote control capability for the plant.

Response: There is minimal support to make FAC-001 prescriptive. The above recommendations can be documented in a technical guidance document for industry.

Transition Category	Operating – Technical Guidelines

Active Power Control Capabilities Recommendations:

- **Require curtailment capability, but avoid requirements for excessively fast response:** Variable generation can respond rapidly to instructions to reduce power output. In many cases response is faster than conventional thermal or hydro generation. However, there have been cases where proposed grid codes have made excessive requirements for speed of step response to a curtailment order. This is technically challenging and should be avoided. A (Δ) 10 percent (%)/s change for rate of response to a step command to reduce power output is reasonable. This rate of response to step instructions should not be confused with deliberate imposition of ramp-rate limits, as discussed next. Active power considerations are not driving reliability requirements at this time. Some conventional generation can reach or even exceed these rates. Most cannot. The project team is not aware of any NERC standards that specify rate of response to re-dispatch commands (of which curtailment is a subset) in this time frame. Typically, plants must respond to economic re-dispatch within minutes. Mechanisms such as markets or other incentives to encourage rapid rate of response from all generating resources should be considered.
- **Require capability to limit rate of increase of power output.**

Response: The ERSTF and IVGTF teams suggest that NERC, through its Operating Committee (OC) and Operating Reliability Subcommittee (ORS), develop an operating practice technical guideline document on active power control capabilities.

Transition Category	Standards Review and/or SAR

Recommendation to NERC Standard FAC-001-0 Modification: Generator facilities smaller than the 75 MVA threshold—especially variable generation facilities—may experience rapid changes in control performance over their lifetimes due to equipment upgrades and replacements. These changes should be captured in updated models. However, substantial modifications on facilities less than 75 MVA may not be captured by the FAC-001 standard or MOD standards. However, substantial modifications on facilities less than 75 MVA may not be captured by the FAC-001 standard or MOD standards.

Modify FAC-001-0 to: "R2: The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items: R2.1.1 Procedures for coordinated joint studies of new or substantially modified facilities and their impacts on the interconnected transmission systems."

Response: NERC, through its Functional Model working group and the Standards Committee, needs to examine the present definitions for the BPS and consider modifications that could include smaller generation facilities.

Transition Category	Standards Review and/or SAR

Recommendation to NERC Standard FAC-001-0 Modification: The following statement should be added to the FAC-001-0 standard as an appendix for clarifying R3.1.17: "Preliminary or approximate power flow and dynamic models may be adequate for the preliminary assessment of interconnection impacts, or to represent existing and proposed projects that are not in the immediate electrical vicinity of the facility being studied. However, detailed dynamic (and possibly transient) models for the specific equipment may be needed for the System Impact Study and Facilities Study to represent the facility and other equipment in the electrical vicinity. Generic non-proprietary publicly available models are more appropriate for the NERC model building process covered by existing MOD standards, although validated generic models with specifically tuned parameters may be adequate for interconnection studies. The models for interconnection studies must be acceptable to the Transmission Owner in terms of simulation platform, usability, documentation, and performance."

Task 1-4 Flexibility Requirements and Metrics for Variable Generation: Implications for Planning Studies	
Transition Category	ERSTF

Recommendations:

- Probabilistic planning methods being developed in NERC's IVGTF Task 1-6 will be a vital improvement to assess required flexibility.
- As part of developing the Variable Generation Reference Guide (Task 3-1 Recommendation Report), a set of best planning practices to design systems with sufficient system flexibility to accommodate targeted levels of variable generation should be documented.

Transition Category	Data Collection & ERSTF

NERC Reliability Metrics Working Group (RMWG) Agreed-Upon Metrics Recommendations:

- Develop and collect metrics that measure flexibility needs for variable generation. For example, calculating a set of ramp and intensity metrics can provide insights on flexibility trends.
- Compare projected and actual annual energy levels from variable generation.
- Measure variable generation performance factors such as capacity factors and peak coincidence factors.
- Conduct planning studies to account for this increased flexibility requirement.

Transition Category	Planning – Technical Guidelines

Recommendations:

- Develop production cost models, including transmission models, to assess the interaction between the dispatchability of wind and transmission.
- Extend use of statistical analysis of hourly and sub-hourly wind plant output and net-load data (mainly simulated but some historical data was used where available) to ensure that production cost models adequately capture ramp rate and minimum generation constraints and account for regulation requirements.
- Wind forecast error models to account for operational impacts caused by the uncertain nature of variable generation (wind forecasting is covered by Task 2-1).

Task 1-5 Potential Reliability Impacts of Emerging Flexible Resources	
Transition Category	Research and Development

Recommendation: The electric power industry should pursue research and development activities to assess the flexibility needs for the regional and interregional systems of North America as well as evaluate the benefits of flexible resources and technologies (i.e., Demand Response (DR), electric and thermal energy storage, and plug-in electric vehicles (PEVs)) on their respective systems.

Transition Category	No Action

Recommendation: If all resources are provided equal opportunity and information as to power system reliability needs, markets and commercial viability should determine what resources provide specific reliability functions to the grid.

Transition Category	No Action

Recommendation: If the emerging flexible resources addressed in this report (i.e., Demand Response (DR), electric and thermal energy storage, and PEVs) are to play a significant role in providing the additional flexibility needed to

accommodate high levels of variable generation, the barriers and limitations identified in this report must be addressed.	
Transition Category	Research and Development
Recommendation for Technical Development: Develop an operational infrastructure that provides visibility and control (direct or indirect) of distributed resources such as Demand Response and PEVs: 1) Appropriate communication systems and methods of aggregating the resources into larger resource blocks are likely needed. System operators will need to understand the operational state and energy capacity available to the system in real time via full integration into energy management systems (EMS) and market operation systems. This development includes technical, administrative, and commercial aspects. 2) Aggregation of the resources into larger blocks will require developing the administrative processes to aggregate and bid the blocks of resources into the appropriate markets.	
Transition Category	No Action
Recommendation for Market Development: Adjust market rules that unnecessarily limit the types of resources for providing specific reliability functions. Some markets specifically designate some classes of resources as unable to participate in supplying some services: 1) Market rules should be adjusted to allow a variety of resource types to participate within stated performance specifications. Resource developers can then determine whether they can package any resource type to meet the performance criteria in an economically viable manner. Thus, market rules should be reviewed in all regions to remove any unnecessary restrictions. 2) The development of a tariff for PEV owners that would discourages charging during peak hours and encourages charging during off-peak hours. 3) For commercial purposes, incent PEVs to charge at appropriate times (off peak).	
Transition Category	Definition Revisions/Addition By NERC
Recommendation: Adjust regional or federal Reliability Standards that limit resources that can be used for providing specific reliability functions. Similar to market rules, Reliability Standards may also limit certain resource groups from providing some reliability functions: Reliability Standards may also limit certain resource groups from providing some reliability functions. For example, the NERC Glossary definition of spinning reserve references “unloaded generation,” which has been interpreted as prohibiting load from participating. As with market rules, federal and regional reliability standards should be adjusted, if necessary, to allow all resource groups to participate in providing reliability services within specified performance criteria.	
Transition Category	NERC Training & Education
Recommendation: Advances and enhancements that inform all resources of the value of needed flexibility services and incent desired response while discouraging undesired response will be needed; for example, the development of a tariff for PEV owners that would discourage charging during peak hours and encourage charging during off-peak hours.	
Task 1-6 Probabilistic Methods	
Transition Category	Research & Development
Recommendations: • **Reserves:** The level of specific reserves needed for VG integration is broadly understood; however, specific methods have not been rigorously tested and compared. The application of stochastic methods appears promising but needs validation and acceptance if the methods are to be successfully used. • **Dispatch:** There is emerging work on probabilistic methods to dispatch conventional generation to minimize cost and maintain reliability in the presence of high levels of VG; however, there is a gap between academic work and practice as a result of more limited experience with high levels of VG.	

- **Commitment:** There has been considerable interest in stochastic unit commitment. Methods and approaches vary, and most of this work resides in the academic/research domain. Collaboration to evolve and move these methods into actual practice, when appropriate, is needed.
- **Maintenance:** Maintenance scheduling may be more difficult in market regions where there is limited central authority to coordinate scheduled maintenance, and high levels of VG will likely have a significant influence. Methods to quantify the risk of both capacity shortfalls and flexibility shortfalls can be developed and tested in industry.
- **Generation planning:** There have been new methods developed to begin quantifying flexibility needs and risks of insufficient flexibility within generation expansion planning algorithms, so that results balance investment in VG with investments in technologies providing the flexibility that VG requires. There is room for improvement in these methods and a need to evolve and move these approaches from the research community to industry practice.

Transition Category	Planning – Technical Guidelines

Recommendations:

- Transmission planning: There is evidence that stochastic approaches to transmission planning may yield more robust solutions; combining such methods with co-optimization of generation and planning decisions is particularly appealing, but computationally challenging. However, these methods are new/emerging, and additional research and deployment of such methods may be useful.
- Grow appreciation for the ways in which the future power system will change. Variable generation is a catalyst for this change in viewpoint, but it is certainly not the only driver toward a different future system that challenges some of our traditional assumptions and practices.
- Work to develop and demonstrate efficient probabilistic techniques and solutions that are capable of addressing full-scale industry problems.

Transition Category	NERC Training & Education

Recommendation: Improve the understanding of probabilistic methods within the industry. The research community needs to work more closely with the industry to clearly demonstrate the benefits of probabilistic methods. The industry needs to clearly communicate shortcomings in deterministic methods and areas that probabilistic methods can be most fruitful. Cooperative efforts of the research and industry communities are needed to overcome the challenges in terms of both understanding and demonstration.

Transition Category	NERC Data Collection

Recommendation: More and better data are needed to allow the research and demonstrations to be meaningful and realistic—from real power systems, from VG resources, and for future VG deployment scenarios. Collecting and maintaining large data sets can be expensive; however, stochastic methods generally require data that may not currently be readily available. We encourage industry discussion of the trade-offs and costs vs. benefits of collecting data that could help inform stochastic methods and the more rigorous assessments of various risks associated with power system planning and operations with high levels of VG.

Transition Category	Planning – Technical Guidelines

Recommendation: Because we envision a significant increase in the development and application of stochastic methods to help analyze the impacts of VG, we recommend that NERC perform a bi-annual assessment of development in this area. The IVGTF would be an appropriate home for this work.

Task 1-7 Performance of Distributed Energy Resources During and After System Disturbance Voltage and Frequency Ride-Through Requirements

Transition Category	NERC Reliability Assessment

Recommendation: In the short term, NERC should engage in current efforts to revise DER interconnection standards by providing information; supporting the efforts of IEEE with transmission reliability subject matter experts; raising industry, regulator, and policy maker awareness; and encouraging the consideration of the explicit VRT and FRT for DERs.

Transition Category	NERC Staff – External Coordination Activity

Recommendations for IEEE Standard:

- The initial focus should be on potential ways to adopt minimum-tolerance thresholds for VRT and FRT in IEEE Standard 1547 while balancing against other important distribution issues such as safety and protection/coordination.
- The task force also offers general guidelines on VRT and FRT specifications for distributed VERs and other DERs, for consideration in the P1547a process or future IEEE Standard 1547 revisions.

Task 1-8 Potential Bulk System Reliability Impacts of Distributed Resources

Transition Category	Research & Development

Recommendation: NERC, state regulators, and/or industry should develop an analytical basis for understanding the potential magnitude of adverse reliability impacts and how that magnitude changes with penetration of DERs and system configuration/composition.

Transition Category	NERC Training & Education

Recommendation: As many DER issues may be beyond the scope of NERC's authority, and since it may be feasible to address these issues through non-NERC avenues (such as through market rules, vertically integrated operations, or state programs), it is recommended that NERC work with the affected entities in the different regions, including state agencies having jurisdiction over DER, RTOs, and vertically integrated utilities, to develop appropriate guidelines, practices, and requirements to address issues impacting the reliability of the BES resulting from DERs.

Transition Category	Planning – Technical Guidelines

Recommendation: Based in part on the analytical results and the broad experience of generation, transmission, and distribution owners and operators, specific recommendations for changes to operating and planning practices, state programs, and pertinent NERC Reliability Standards should be developed.

Task 2-1 Variable Generation Power Forecasting for Operations

Transition Category	Operating – Technical Guidelines

Recommendation: Wind and solar plants require real-time meteorological and electrical data through SCADA systems using standard communication protocols for use in forecasting and system operation, including power, availability, curtailment, and meteorological data.

Response: FERC Order 764 has largely addressed this issue for wind. A technical guideline may be appropriate to recommend similar measures for solar.

Transition Category	Operating – Technical Guidelines

Recommendation: Wind plant output forecasts, often several of them, should be adopted as standard system and market operation tools for economic operation and system reliability purposes. Multiple types of forecasts and forecast optimizations are practical and important:

- Clarity around how a particular forecast will be used must be clearly defined for both the provider and user of a forecast product.
- Given the value of incrementally better forecasts, system operators should consider a multiple forecasting provider model (aka, the German approach) rather than using a single external or internal forecasting service.

Transition Category	ERSTF

Recommendation: Wind plant output forecasts, often several of them, should be adopted as standard system and market operation tools for economic operation and system reliability purposes. Multiple types of forecasts and forecast optimizations are practical and important:

- A ramp forecast is possible and useful, but may need to be optimized for a different use than the conventional power forecast. The "chance of ramp" indication is valuable even if it is not perfect. In fact, the complexity of weather events guarantees that ramp forecasts will not be perfect.
- It may be beneficial to tune the wind power forecast to take into account the state of system. Morning load pickups and evening load drop-offs may require better knowledge of the likelihood of wind ramps, and should be investigated by the system operator.

Transition Category	Operating – Technical Guidelines

Forecasts Recommendations:

- Initial use of aggregate, regional, and individual wind plant forecasts by reliability coordinators in the control room is a logical first step.
- Use of the forecast in unit commitment planning is very important. Adjusting to clear the day-ahead market with a combined load and wind power forecast (rather than ignoring the wind) would improve both the economics and reliability of system operation.

Transition Category	Research and Development

Forecasts Recommendation: Probabilistic methods are increasingly important, and the uncertainty distributions around all forecasts (including but not limited to the variable generation power forecasts) should be addressed more explicitly. As a minimum, the use of a "chance of ramp" forecast probability should be used to identify whether or not additional reserves are needed.

Transition Category	ERSTF

Recommendation: There are overwhelming benefits from adjusting operating rules and practices, and these adjustments may have more benefit to both reliability and economic operations than the forecasting alone.

- Sub-hourly markets with sufficient liquidity, or the ability to otherwise dispatch generation closer to real time with sufficient flexibility, can be very effective in addressing the variability and uncertainty of variable generation.

Transition Category	Operating – Technical Guidelines

Recommendation: There are overwhelming benefits from adjusting operating rules and practices, and these adjustments may have more benefit to both reliability and economic operations than the forecasting alone:

- Incorporating the variable generation power forecast into unit commitment is important for economical and reliable operation.

Transition Category	No Action

Recommendations: There are overwhelming benefits from adjusting operating rules and practices, and these adjustments may have more benefit to both reliability and economic operations than the forecasting alone:

- Negative price offers for resources should be included in markets that do not yet offer this capability to help maintain reliable and economical operation.
- The benefits of larger balancing areas with fewer transmission constraints are overwhelming. Resolving transmission constraints is critical because larger balancing areas lose many of the benefits associated with size if constraints are in play. Areas with sufficient transmission capacity are exploring how to achieve the benefits of larger areas through direct balancing area consolidation or through efforts at "virtual consolidation" where separate balancing areas work together on particular issues. Smaller areas, such as island systems, will have special challenges that require additional control. Larger operating areas, with minimal transmission constraints and diverse variable generation assets, should be capable of dealing with the expected levels of variable generation.

Transition Category	Research and Development

Recommendations: Ongoing innovation is needed, with both government and private industry involvement. Innovation is needed to continue to improve forecasting products. This requires multiple cooperating players:

- Government R&D and forecasting centers for improved data systems, model development, and general operational weather deliverables.
- A vibrant, competitive forecasting service community to assist in the R&D, applications, and services for business-augmented use of operating data with forecasting products.
- Developers of system operating tools and methods, both in private companies and in the system operator organizations, to deal with the true variability and forecast probability distributions that are implicit to our real-world systems, system operators, and stakeholders.

Transition Category	No Action

NERC should enhance its Reliability Standards by organizing Standard Authorization Requests or supporting existing standard development processes including but not limited to the following standards that require potential changes:

Response:

- **TOP-002 (Normal Operations Planning)**: Project 2014-03 is revising a significant number of standards in the TOP and IRO families. In support of the proposed revisions, retirement of TOP-002-2.1b Standard, and the approval of TOP-002-4 standard has been requested. The currently proposed draft of TOP-002-4 includes proposed R1, which states, "Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs)."" Further, the currently proposed revision of TOP-003-3 includes the following proposed revision of the term as follows: "Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)" The use of the defined term "Operational Planning Analysis" in the currently proposed draft of TOP-002-4 allows for the inclusion of load forecasting as well as variable generation data for use in operations planning and analysis.
- **TOP-006 (Monitoring System Conditions)** Requirement 1.1: Currently proposed draft TOP-003-3, R5 directs the Generator Owner to respond to a request for specific data rather than initiate the transfer of data, which will allow the applicable registered entity requesting the data to determine the appropriate input required to meet their monitoring responsibility.
- **COM-002 (Communication and Coordination):** Standard is revised; the new language is sufficient.

- **IRO-005 (Reliability Coordination – Current-Day Operations):** The Project 2014-02 Standards Applicability for Dispersed Generation Resources Standards Drafting Team performed a review of all standards that apply to Generation Owners and/or Generator Operators, determined how each standard requirement should be appropriately applied to dispersed generation resources, and categorized them as follows:
  - The existing standard language was appropriate when applied to dispersed generating resources and does not need to be addressed;
  - The existing standard language was appropriate when applied to dispersed generating resources, but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed generating resources; and
  - Detail is provided in a white paper that is posted on the website for Project 2014-02. It was developed by the drafting team with the intent that the drafting team will modify this document over the course of Project 2014-02 to document the team's rationale and technical justification for each standard until the work of the Drafting Team is complete.

Transition Category	Operating – Technical Guidelines

Recommendation: NERC should enhance its Reliability Standards by organizing Standard Authorization Requests or supporting existing Standard development processes including but not limited to the following standards that require potential changes:

- FAC-001 (Facility Connection Requirements) – (Section R2): The currently proposed draft of FAC-002-2 addresses the responsibilities of the Generator Owner by stating, "Each Generator Owner seeking to interconnect new, or materially modify existing, generation Facilities shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator . . . " This requirement is sufficiently broad to facilitate the Transmission Owner's requests for specific information, cooperation, and collaboration from the Generation Owner.

Recommendation: Investigated developing a new NERC Reliability Standard that provides for regional forecasts and local wind/solar facility wind forecasts to schedule variable generation.

Transition Category	ERSTF

Recommendation: NERC should enhance its Reliability Standards by organizing Standard Authorization Requests or supporting existing standard development processes including but not limited to the following standards that require potential changes:

- **BAL-002 (Disturbance Control Performance**) – Requirement 3.1: The ERSTF Ramp and Frequency Support subgroups should consider the value of treating unexpectedly sudden changes of wind and solar power as "credible contingency" events under the BAL-002 standard. If the change in wind or solar power was not well forecast, the ERSTF should also consider whether slower ramps (not just "sudden loss" events) should be included as contingency events.

Task 2-2 Reliability Considerations for BA Communications with Increased Variable Generation

Transition Category	No Action

Recommendation: Transmission Operator would list their specific requirements not only for generation connected to the transmission system but also any generation in the footprint that is within the area operated by the Transmission area that will impact the operation of the Balancing Authority and Bulk Electric Transmission System.

Response: FAC-001-1, subject to enforcement, includes as R1 the requirement, "The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements."

Requirements R2 and R3 of this standard apply to any GO that has an external party applying for interconnection to the GO's existing Facility in order to connect to the transmission system. This scenario is uncommon and there is no

precedent for applicability of this standard to dispersed-power-producing resources known to the SDT. Current practice primarily includes the GO stating that they will comply with the standard if this scenario is ever realized. This standard allows the GO to specify the conditions that must be met for the interconnection of the third party, thus providing inherent flexibility to tailor the requirements specifically for the unique needs of the Facility. Therefore, the applicability of FAC-001 does not need to be changed for dispersed-power-producing resources.

Transition Category	Data Collection

Data and communication capabilities should be provided to the BA by all generation operating in the BA that has an impact on the reliability of the BES.

- Net and Gross MW and MVAR output
- Meteorological data (wind speed, wind direction, temperature, and barometric pressure)
- High- and Low-Sustained Limit
- Normal and emergency ramp-rate capability
- Turbine availability
- Breaker Status
- Modeling data (static information)
  - Tower height
  - Relay settings (including UFR settings)
  - Type of turbines
- Voice circuit
  - Available communication to plant operator
  - Communication to address real-time operational issues
- Set point and curtailment communication (market areas)

Transition Category	No Action

Recommendation: COM-002 – Consider applying the standard to all generation 10 MW or greater. This improvement in communication will not only improve data communication but also require the GOP to be available to address real-time operational issues. This can be accomplished with manned resources or remote control and monitoring of the facilities.

Recommendation: PRC-001 – Under R3, make this requirement applicable to facilities 10 MW or greater. This will ensure that the necessary relay coordination has taken place to reduce the reliability impact of unexpected relay operation, specifically operation of under- and overfrequency relays. The generation should be set lower than the Underfrequency Load Shedding relays in the region to ensure generation tripping does not compound underfrequency operation similar to the European event.

Response:

1. This would conflict with the effective BES definition, which is comprised of the following: “Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

   Inclusions:

   Inclusion 1: Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.

   Inclusion 2: Generating resource(s) including the generator terminals through the high side of the step-up transformer(s) connected at a voltage of 100 kV or above with:

   a) Gross individual nameplate rating greater than 20 MVA; or,

   b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

   Inclusion 3: Blackstart Resources identified in the Transmission Operator’s restoration plan.

Inclusion 4: Dispersed-power-producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above.

Thus, the facilities designated as BES are:

a. The individual resources, and

2. The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. "Further, even when the conflict with the effective Bulk Electric System definition is disregarded, this recommendation appears to be adequately addressed through the structure of TOP-003-3, which provides a means by which the Transmission Operator may obligate Generator Operator availability to address real time operational issues if necessary by way of a documented specification. TOP-003-3 R1. states: "Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments," and further requires as R1. Part 1.1-1.4: the data and information needed; data precocity; and deadlines for data provision. TOP-003-3 R3 states, "Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment." TOP-003-3 R5. States, "Each . . . Generator Operator . . . receiving a data specification in Requirement R3 . . . shall satisfy the obligations of the documented specifications." Therefore, compliance with the standard will generate a documented specification created by the Transmission Operator that will specify the precocity and deadlines for data provision (TOP-003-3 R1. Part 1.1-1.4), distribution of such documented specification to the Generator Operator (TOP-003-3 R3.), who is then required to satisfy the obligations of the documented specifications for data (TOP-003-3 R5). The structure of TOP-003-3 is such that the Transmission Operator may obligate Generator Operator availability to address real-time operational issues if necessary through the documented specification.
3. The Project 2014-02 Standards Applicability for Dispersed Generation Resources Standards Drafting Team performed a review of all standards that apply to Generation Owners and/or Generator Operators and determined how each standard requirement should be appropriately applied to dispersed generation resources and categorized them as follows:

• The existing standard language was appropriate when applied to dispersed generating resources and does not need to be addressed; Thee existing standard language was appropriate when applied to dispersed generating resources but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed generating resources; and

• The existing standard language was appropriate when applied to dispersed generating resources but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed generating resources; and

• The existing standard language needs to be modified in order to account for the unique characteristics of dispersed generation resources. This could be accomplished through the applicability section of the standard in most cases or, if required, through changes to the individual requirements.

The COM standards focus on communication between the RC, BAs, TOPs, and GOPs. The only requirements in any of the current or future enforceable standards that apply to the GOP are clearly intended to apply to the individual GOP registered functional entity (i.e., requires communication between GOPs, TOPs, BAs, and RCs), not the constituent Elements it operates. Consequently, there is no need to differentiate the GOP's obligation for dispersed-power-producing resources from any other resources. Therefore, the applicability of the COM-001-2, COM-002-2a, and COM-002-4 standards that were reviewed do not need to be changed for dispersed-power-producing resources.

PRC-001-1.1 — System Protection Coordination: Requirement R1 requires GOPs to be familiar with the purpose and limitations of Protection System schemes applied in their area. The recently approved changes to the BES definition extend the applicability of this requirement. Often this familiarity is provided to GOP personnel through training on the basic concepts of relay protection and how it is utilized. The basic relaying concepts utilized in protection on the aggregating equipment at a dispersed generation site typically will not vary significantly from the concepts used in Protection Systems on individual generating units.

Requirement R2 requires that GOPs report protective relay or equipment failures that reduce system reliability. Protective System failures occurring within a single individual generating unit at a dispersed-power-producing resource will not have any impact on overall system reliability and thus it should not be necessary for GOPs to report these failures to their TOPs and host BAs. Only failures of Protection Systems on aggregating equipment have the potential to impact BPS reliability and may require notification. When interpreted as stated above, no related changes should be required to the existing PRC-001-1 standard, as the BES definition changes do not have an impact on these requirements. Requirement R3 requires GOPs to coordinate new protective systems. The coordination of new protective relay schemes and changes to existing protective relay schemes should occur to aggregating equipment protection only if a lack of coordination could cause unintended operation or non-operation of an interconnected entity's protection, thus potentially having an adverse impact to the BPS.

Existing industry practice is to share/coordinate the protective relay settings on the point of interconnect (e.g., generator leads, radial generator tie line, etc.) and potentially the main step-up transformer, but not operating (collection) buses, collection feeder, or individual generator protection schemes, as these Protection Systems do not directly coordinate with an interconnected utility's own Protection Systems. Relay protection functions such as under- and overfrequency and under- and overvoltage changes are independent of the interconnected utility's protective relay settings. The setting criteria are defined in PRC-024.

Requirement R5 requires GOPs to coordinate changes in generation, transmission, load, or operating conditions that could require changes in the Protection Systems of others. A GOP of a dispersed generation resource should be required to notify its TOP of changes to generation, transmission, load, or operating conditions on an aggregate Facility level.

Project 2007-06 – System Protection Coordination and Project 2014-03 – Revisions to TOP and IRO standards include various aspects of this standard or address certain requirements in other standards.

For these reasons, the DGR SDT coordinated with the other SDTs currently reviewing this standard and recommended revisions to R3.1 to indicate that coordination by a GOP with their TOP and host BA of new protection systems or changes to protection systems on individual generating units of dispersed-power-producing resources is not required.

Transition Category	No Action

Recommendation: All generators 10 MW or greater within a BA regardless of interconnection point shall provide:

- Breaker status to the BA/TOP (FAC-001)
- Current MW and MVAR output (FAC-001)
- Voice circuit for communication of real-time instruction (COM-002)
  - Remote control of resources is adequate but should be capable of handling real-time operational issues.
- Coordination of relay settings, specifically under-frequency coordination (FAC-001)

Response:

Mandating how system impact and facilities studies are completed is not appropriate and should not be part of a Reliability Standard. This level of prescriptiveness goes against the results-based approach for standards. FAC-001 was just revised and the technical experts on the SDT and stakeholders did not agree that this level of prescriptiveness was appropriate. Also, this suggestion inappropriately goes below the BES threshold.

Transition Category	No Action

Recommendation: The following should also be required for all generators 10 MW or greater within a BA regardless of interconnection point, if a significant impact has been identified in an interconnection study:

- Resource schedules with outage information (FAC-001)
- Meteorological data for forecasting (FAC-001)
- Availability (FAC-001)

- High- and Low-Sustained Limit (FAC-001)
  - Including high-wind cutout
  - Temperature limitations
  - Any other operational restrictions

Response: These requirements have already been addressed by FERC Order 764, which requires such dynamic and static data for doing wind power forecasting. Mandating how system impact and facilities studies are completed is not appropriate and should not be part of a Reliability Standard. This level of prescriptiveness goes against the results-based approach for Standards. FAC-001 was just revised and the technical experts on the SDT and stakeholders did not agree that this level of prescriptiveness was appropriate. Also, this suggestion inappropriately goes below the BES threshold.

Transition Category	No Action

FAC-001: Transmission Operator would list their specific requirements not only for generation connected to the transmission system but also any generation in the footprint that is within the area operated by the Transmission area that will impact the operation of the Balancing Authority and Bulk Electric Transmission System.

Response: Mandating how system impact and facilities studies are completed is not appropriate and should not be part of a Reliability Standard. This level of prescriptiveness goes against the results-based approach for standards. FAC-001 was just revised and the technical experts on the SDT and stakeholders did not agree that this level of prescriptiveness was appropriate.

Transition Category	No Action

TOP-001: Under R3, require all generation facilities 10 MW or greater to comply with reliability directives from the Balancing Authority or the Transmission Operator. Under R7, all generation facilities 10 MW or greater provide notice to the Balancing Authority and the Transmission Operator before removing generation facilities from service to reduce the reliability impact to the system.

TOP-002-2b: Under R3, require all generation facilities 10 MW or greater to provide current, next-day, and seasonal operations with the host Balancing Authority and Transmission Provider. This will improve the reliability studies of the BES.

TOP-003-1: For generation facilities 10 MW or greater, require outage coordination of generation facilities including telemetering equipment and voltage regulation equipment so that interconnected operations are coordinated between Balancing Authorities, Transmission Operators, and Reliability Coordinators.

Response: The Project 2014-02 Standards Applicability for Dispersed Generation Resources Standards Drafting Team performed a review of all standards that apply to Generation Owners and/or Generator Operators and determined how each standard requirement should be appropriately applied to dispersed generation resources. They are categorized as follows:

- The existing standard language was appropriate when applied to dispersed generating resources and does not need to be addressed.
- The existing standard language was appropriate when applied to dispersed generating resources but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed generating resources.
- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed generation resources. This could be accomplished through the applicability section of the standard in most cases or, if required, through changes to the individual requirements.

Detail is provided in a white paper posted on the website for Project 2014-02. It was developed by the drafting team with the intent that the team will modify this document over the course of Project 2014-02 to document the Drafting Team's rationale and technical justification for each standard until the work of the drafting team is complete.

Task 2-3 Ancillary Services and Balancing Authority Area Solutions to Integrating Variable Generation

Transition Category	Operating – Technical Guidelines
Recommendation: Each region or reserve-sharing group should permit Contingency Reserve deployment under imbalance energy circumstances made more likely with the increasing penetration of renewables.	
Transition Category	Operating – Technical Guidelines
Recommendation: The task team recommends that the generator interconnection requirements be modified to require this dispatchable control capability interfaced with the grid operator for all new variable generation resource developments.	
Transition Category	Operating – Technical Guidelines
Recommendation: Regional market operators and other grid operating entities should develop the ability to consider transmission service by prioritizing variable resources when allocating curtailment responsibility to variable output resources during reliability-limited operating conditions.	
Transition Category	ERSTF
Recommendation: BAL-001-0.1a – Real Power Balancing Control Performance: Increased Balancing Authority collaboration reduces cost overall and is valuable for the integration of variable generation.	
Transition Category	ERSTF
Recommendation: BAL-002-0 – Disturbance Control Performance – The standard drafting team should consider if Contingency Reserves can be used to meet DCS requirements for wind-related events. Reserve calculation procedures should be updated to take into account variable energy resource events, including ramping events that are much slower than the instantaneous contingency events caused by conventional generators and transmission failures. This could impact recommendations for Contingency Reserve Policies, DCS, DCS response time, and DCS recovery time. Alternatively: The current BAL-002 and DCS do not apply to variable energy resource events because they are too slow. There is no need to change BAL-002 due to variable energy resource integration. Balancing Authorities would need to deal with the risk of tail events with their own resources—or with different resources than the current DCS resources. Ultimately, it would be more efficient to mitigate the risk of rare tail events by using pooled reserves, especially in high-penetration scenarios. Action: IVGTF2-3 should collaborate with the standards drafting team to establish another requirement to accommodate variable energy resources and their tail events.	
Transition Category	No Action
Recommendation: IRO-005-3-1a Reliability Coordination — Current-Day Operations – A NERC Reliability Standard is required to communicate variable generation derates due to turbine outage conditions and plans. Currently issues may arise if part of a wind plant is out of service and operators are not aware of the number of turbines unavailable and the duration of the forced or planned outage. **Response:** This recommendation appears to be adequately addressed through the requirements of IRO-010-1a, which is currently subject to enforcement. IRO-010-1a includes as R3 the requirement, "Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship." TOP/IRO project is working on an outage coordination standard as well—IRO-017-1, Outage Coordination.	
Transition Category	No Action

Recommendation: A NERC standard is required to communicate variable generation derates due to turbine outage conditions and plans. Currently issues may arise if part of a wind plant is out of service and operators are not aware of the number of turbines unavailable and the duration of the forced or planned outage.

Response: This recommendation appears to be adequately addressed through the requirements of IRO-010-1a, which is currently subject to enforcement. IRO-010-1a includes as R3 the requirement, "Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship."

Transition Category	No Action

Recommendation: TOP-002-2&A Normal Operations Planning The standard should be enhanced to provide guidance on incorporation of variable energy resource events into the planning process.

Response: Project 2014-03 is revising a significant number of standards in the TOP and IRO families. In support of the proposed revisions and retirement of the TOP-002-2.1b standard, the approval of TOP-002-4 has been requested. The currently proposed draft of TOP-002-4 includes proposed R1, which states: "Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs)." Further, the currently proposed revision of TOP-003-3 includes the following proposed revision of the term as follows: "Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)"

Transition Category	No Action

Recommendation: TOP-006-1&2 Monitoring System Conditions – Expand R4 to require similar information and prediction of variable generation output:

R4. Each Transmission Operator and Balancing Authority shall have information including weather forecasts and past load, and variable generation patterns are available to predict the system's near-term load and variable generation pattern.

Response: Project 2014-03 is revising a significant number of standards in the TOP and IRO families. In support of the proposed revisions, retirement of TOP-006-2 has been requested, and it has been proposed that requirement R4 of TOP-006-2 transition to proposed draft standard TOP-003-3 R1 & R2. The current proposed draft requires the Transmission Operator to "maintain a documented specification for the data necessary for it to perform its Operational Planning Analysis," and provides the following proposed draft definition: "Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)" The current proposed draft standard maintains sufficient breadth to allow the Transmission Operator to determine the appropriate data required to perform their Operational Planning Analysis.

Task 2-4 Operating Practices Procedures and Tools	
Transition Category	ERSTF

Recommendation: BAL-002 (Disturbance Control Performance) – The standard may need to be revised to include sudden changes in wind output as "credible contingencies" under the standard. This would ensure that these events are analyzed during reserve calculations. The applicable section of the standard is Requirement 3-1. Additionally,

changes to this standard may need to be addressed with various reserve-sharing groups, many of which have differing rules regarding contingencies.

Transition Category	ERSTF

Recommendation: BAL-005 R-11 – This standard may need to be updated to include the various types of ramp rates that a Balancing Authority may need to use in the scheduled interchange values to calculate ACE. Controlled and uncontrolled ramp rates may need to be included in the analysis since both types can be encountered by variable generation.

Transition Category	ERSTF

Recommendation: COM-002 (Communication and Coordination) – The standard may need to be revised to clarify the meaning of "voice and data links" as used in the standard. To avoid problematic interpretations, the standard should specify that "voice and data links" are those identified in Interconnection Agreements or other governing agreements between the Transmission Operators and the variable generator.

Transition Category	Standard Review and/or SAR

Recommendation: EOP-002 R6 – This standard may need to be updated to reflect curtailment capabilities of various types of generation as one of the possible remedies available to Balancing Authorities. This would ensure that a Balancing Authority has examined various types of remedies that are available when experiencing problems meeting the Control Performance and Disturbance Control Standards.

Response: Good recommendation especially in areas that do not yet have much experience with wind and PV plants. But variable renewables are just one of many technologies. There seems to be a trend for standards to be less specific rather than more. (For example, "The currently proposed draft requirements remove the phrase "monitoring equipment" in favor of the statement "shall monitor," which is applied to each appropriate registered entity and their corresponding responsibility. Employing the phrase "shall monitor" is sufficiently broad to allow the applicable registered entity to determine the appropriate input required to meet their monitoring responsibility.") So if the standard(s) are silent on considering resources like demand response as well as conventional generation, it may not be appropriate to include a specific reference to variable renewables. Perhaps if there is an accompanying guideline or reference document it could be included there.

Transition Category	Standard Review and/or SAR

Recommendation: IRO-004 (Reliability Coordination – Operations Planning) – This standard may need to be updated to reflect forecasting information available to variable generation that is to be made available for next-day studies. Currently, the standard indicates that parties "shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known Interchange Transactions." Forecasting of variable generation could be added to the list in order to provide an accurate day-ahead study.

Response: This recommendation is directed at the establishment of new requirements. In this case, industry may initiate a SAR if they perceive one is needed.

Transition Category	Standard Review and/or SAR

Recommendation: IRO-005 (Reliability Coordination – Current-Day Operations) – This standard may need to be updated to include active monitoring of forecasting conditions such as weather fronts, icing, and/or high wind conditions by the Reliability Coordinator. The active monitoring would ensure that the Reliability Coordinator is aware of conditions that may arise in the immediate future. This would create consistency with the purpose of the standard, which is: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."

Response: It appears this recommendation is directed at the establishment of new requirements. In this case, industry may initiate a SAR if they perceive one is needed.
This is the current DGR SDT position (from currently posted version of the white paper):

4.6.2 IRO-005 — Reliability Coordination — Current-Day Operations.

The purpose of this standard and its requirements as they relate to GOPs is to ensure that when there is a difference in derived limits, the BES is operated to the most limiting parameter. A difference in derived limits can occur on any Element and, therefore, any limitation of the applicability of this standard may create a reliability gap. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. Therefore, the applicability of IRO-005 does not need to be changed for dispersed-power-producing resources.

Transition Category	Standard Review and/or SAR

Recommendation: TOP-002 (Normal Operations Planning) – This standard may need to be updated to include a section about forecasting, identifying the data submitted by variable generators as the method of providing generation information to the Transmission Operators. It also needs to recognize forecasting as the best way to estimate generation, albeit subject to some unavoidable uncertainty due to the variability and complexity of weather conditions. This would assist in system operations, especially in day-ahead or hour-ahead operations.

Response:

- Add language that specifically adds variable wind and solar to the list of things that should be considered:

  The currently proposed draft of TOP-002-4 includes proposed R1, which states: "Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs)." Further, the currently proposed revision of TOP-003-3 includes the following proposed revision of the term as follows: "Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; variable renewable generation forecasts; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages including variable generation availability; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)." The use of the defined term "Operational Planning Analysis" in the currently proposed draft of TOP-002-4, allows for the inclusion of load forecasting as well as variable generation data for use in operations planning and analysis.

The term "Operational Planning Analysis" can include variable generation forecasting as well as load forecasting, so no additional wording is required unless "Operational Planning Analysis" is expanded upon in a glossary or footnote or elsewhere, in which case variable generation forecasting should be explicitly listed as a possible component.

Transition Category	Standard Review and/or SAR

Recommendation: TOP-006 (Monitoring System Conditions) – Requirement 5 discusses the use of "monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action." This standard may need to be revised to include specific tools such as (1) input from a forecaster, or (2) real-time data from wind and solar plants (e.g., meteorological towers, sonic detection and ranging (SODAR), and real-time turbine telemetry).

Response: It appears this recommendation is directed at the establishment of new requirements. In that case, industry may initiate a SAR if they perceive one is needed.

This is the current DGR SDT position (from currently posted version of the white paper):
4.11.5 TOP-006 — Monitoring System Conditions. The purpose of this standard as it relates to GOPs is to ensure BAs and TOPs know the status of all generation resources available for use as informed by the GOP. It should also be noted that the purpose of this standard is to ensure critical reliability parameters are monitored in real time. It then can be extrapolated that the requirement, "GOP shall inform…," is done by sending dispersed-power-producing resource telemetry in real time and through a digital communication medium, such as an ICCP link or RTU. The SDT feels a modification to the applicability of this requirement is necessary for dispersed-power-producing resources. The SDT

is recommending that this requirement be applied at the aggregate Facility level for dispersed-power-producing resources for the following reasons:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20 MVA. If removing less than 20 MVA would cause a burden to the BPS, then the threshold for inclusion in the BES would have been less than 20 MVA.
- Routine maintenance is frequently completed on a small portion of the entire Facility (e.g. 2% of the generators are out of service on any given day) as not to have a significant impact on the output capability of the Facility. Additionally, it is not uncommon to have individual generating units at a dispersed-power-producing resource go into failure mode due to internal factors of the equipment, such as hydraulic fluid pressure tolerances, gearbox bearing thermal tolerances, etc. As such, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.
- As this standard requires real-time monitoring, this is most likely completed through a digital medium such as an ICCP link or RTU. The data that a dispersed-power resource provides to the BA and TOP in real time should include the aggregate active power output of the Facility, among other telemetry points. These data specifications are usually outlined in interconnection agreements among the parties.

Based on the SDT's technical expertise, BAs and TOPs are informed by the GOP of all generation resources available at the dispersed-power-producing resource at the aggregate Facility level. Traditionally the dispersed-power-producing resources are providing the BA and TOP, at minimum, the following telemetry points in real time: aggregate Real Power, aggregate Reactive Power, and main high-side circuit breaker status. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. The SDT has not found or been made aware of a reliability gap that would prompt this team to apply these requirements to any point less than where the dispersed-power-producing resource aggregates and, as such, recommends a modification to the applicability of this requirement for dispersed-power-producing resources.

Transition Category	Standard Authorization Request

NERC Reliability Standards that address the reasonable and effective use of regional forecasts and local wind/solar facility forecasts should be encouraged and used to schedule variable generation to assist in accurate system operation.

Transition Category	Operating – Technical Guidelines

Recommendation: Improving operating practices, procedures, and tools can help reliably integrate variable generation into the power system as well as improve the reliability of the power system in the absence of variable generation.

Transition Category	Enhancement to Modeling

Recommendation: Variability and uncertainty can be reduced through aggregation. Larger aggregations of wind and solar generation are proportionately less variable. Forecast accuracy is also improved for larger wind and solar aggregations. Net variability is also reduced when VERs are aggregated with load, and it is net variability that must be balanced to maintain reliability. The pool of flexible resources (generators and responsive load) increases as the size of the BA increases. Balancing should be conducted over the largest geographic area possible, either through consolidating smaller BAs or through coordinated operations.

Transition Category	ERSTF

Recommendation: The IVGTF suggests that those balancing areas that face significant integration of variable resources consider studying the benefits of sub-hourly scheduling to manage the integration of variable generation. Depending on the current or projected BA system characteristics, assuming sufficient transmission is available, there may be benefits to intra-hour interchange scheduling in the form of reduced ancillary services, more flexibility, and the ability to manage the variability, while still meeting the requirements of NERC's Reliability Standards.

Transition Category	Enhancement to Modeling and Operating – Technical Guidelines

Recommendation: Wind and solar plants should have the capability to send and receive real-time data (meteorological and electrical) through SCADA systems using standard communication protocols for use in forecasting and system operation.

Transition Category	Standard Authorization Request/ERSTF

Recommendation: Wind plant output forecasts, often several of them, should be adopted as standard system and market operation tools for economic operation and system reliability purposes. Ramp forecasts as well as hourly energy forecasts should be considered.

Transition Category	Operating – Technical Guidelines

Recommendation: NERC Regions should consider what control capabilities should be required for new VERs to ensure reliability. Procedures should be developed that limit the use of VER control capabilities to situations where it is required to maintain reliability or when accepting the energy results in excessive costs.

Transition Category	Enhancement to Modeling and Operating – Technical Guidelines

Recommendation: Interconnection requirements for all generation technologies (VER and conventional) need to be designed for anticipated rather than existing conditions, considering aggregate impacts and effects of displacing conventional generation. Interconnection requirements should address control capability, ride-through, inertial response, voltage regulation, etc. It is difficult to modify requirements on existing facilities after the fact.

Transition Category	Operating – Technical Guidelines/ ERSTF

Recommendation: Changes to operating rules and practices are critical:

- Sub-hourly markets with sufficient liquidity, or the ability to otherwise dispatch generation closer to real time with sufficient flexibility, can be very effective in addressing the variability and uncertainty of variable generation.
- Incorporating the variable generation power forecast into unit commitment and dispatch procedures is important for economical and reliable operation.
- More frequent unit commitment can use updated forecasts of VER and load.
- Consider adjusting reserve requirements based on forecast VER output levels. This would allow the reserves to capture the fact that the volatility of wind output is different for different output levels.
- Mechanisms to incent dispatch behavior consistent with system needs. For example, the interaction between variable resources supported by tax credits and renewable energy credits or monetized environmental benefits and a significant proportion of baseload generation with significant minimum generation requirements suggests that the capability to capture negative price offers for resources may be needed to clear markets.
- The benefits of larger balancing areas with fewer transmission constraints are overwhelming. Resolving transmission constraints is critical because larger balancing areas lose much of the benefits associated with size if constraints are in play. Different parts of the country are exploring how to achieve the benefits of larger areas through direct balancing area consolidation or through efforts at “virtual consolidation” where separate balancing areas work together on particular issues. Smaller areas, such as island systems, will have special challenges that require additional control. Larger operating areas, with minimal transmission constraints and diverse variable generation assets, should be capable of dealing with the expected levels of variable generation.

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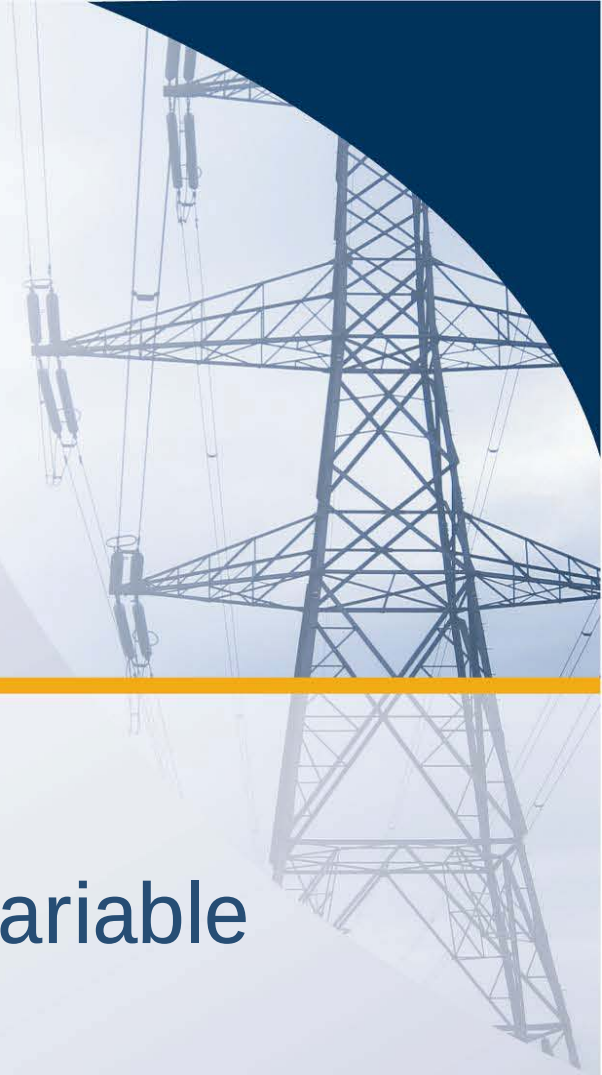

Special Report

Standard Models for Variable Generation

5/18/10

to ensure the reliability of the bulk power system

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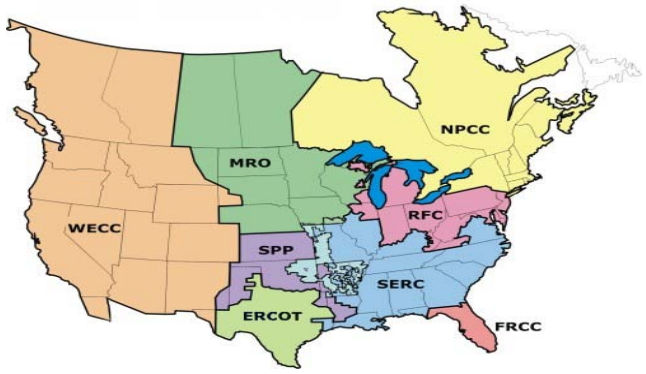
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight Regional Areas as shown on the map below (See Table A).[2] The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: *The highlighted area between SPP and SERC denotes overlapping Regional area boundaries: For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

Table A: NERC Regional Entities

ERCOT Electric Reliability Council of Texas	**RFC** Reliability*First* Corporation
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP** Southern Power Pool, Inc.
NPCC Northeast Power Coordinating Council, Inc.	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro, making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have a framework in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

[2] Note ERCOT and SPP are tasked with performing reliability self-assessments as they are regional planning and operating organizations. SPP-RE (SPP – Regional Entity) and TRE (Texas Regional Entity) are functional entities to whom NERC delegates certain compliance monitoring and enforcement authorities.

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Executive Summary

Existing state and federal energy policies including renewable portfolio standards (RPS) and production tax credits have driven development of wind plants in the U.S. and Canada that presently comprise in excess of 35 GW of installed capacity. This trend is projected to continue with the addition of many other forms of renewable technologies such as photovoltaics. Furthermore, other technologies like plug-in hybrid electric vehicles (PHEV), tidal-power systems, etc. are also on the horizon.

Unlike traditional, non-renewable resources, the output of wind, solar, ocean and some hydro generation resources varies according to the availability of the primary fuel (wind, sunlight and moving water) that cannot be reasonably stored. Therefore, these resources are considered variable, following the availability of their primary fuel source.

The North American Electric Reliability Corporation (NERC) is responsible for ensuring the reliability of the bulk power system in North America. Anticipating the growth of variable generation, in December 2007, the NERC Planning and Operating Committees created the Integration of Variable Generation Task Force (IVGTF), charging it with preparing a report [1] to identify the following:

1) Technical considerations for integrating variable resources into the bulk power system,

2) Specific actions, practices and requirements, including enhancements to existing or development of new reliability standards

One of the identified follow-up tasks from [1] was the need standard, valid, generic, non-confidential, and public power flow and stability models for variable generation technologies, and for a task force to review existing NERC Modeling, Data and Analysis (MOD) Standards to ensure high levels of variable generation can be simulated and appropriately addresses through the existing standards. This document constitutes the results of this review performed by this Task Force. A detailed discussion is provided of model and model validation in general, followed by an account of the current status of models for various variable generation technologies. Then a discussion is provided of the relevant NERC MOD standards and where they will need to be augmented to properly address variable generation.

Thorough out this report reference is made to various forms of models (standard, generic, user-written, 3-phase, etc.). It should be emphasized that the present and imminent need is to have models that are standard (i.e. a defined model structure used by all commercial software tools), publicly available and not specific to any particular design (i.e. “generic” and able to reasonably

represent key performance relevant to bulk power system studies) – this is the focus, which is further elaborate in the report. The process and need for model validation, however, applies to any and all levels of modeling.

An earlier draft of this report and recommendations were presented to NERC's Planning Committee at their March, 2010 meeting. The Committee members urged the IVGTF to pursue NERC reliability standard development. Thus, several NERC Standards Drafting Teams undertaking MOD Standard development will be contacted to present the recommendations from this report for their consideration and incorporation in subsequent updates.

1. Introduction

Existing state and federal energy policies including renewable portfolio standards (RPS) and production tax credits have driven development of wind plants in the U.S. and Canada that presently comprise in excess of 35 GW of installed capacity. This trend is projected to continue with the addition of many other forms of renewable technologies such as photovoltaics. Furthermore, other technologies, like plug-in hybrid electric vehicles (PHEV), are also on the horizon.

Unlike traditional, non-renewable resources, the output of wind, solar, ocean and some hydro generation resources varies according to the availability of the primary fuel (wind, sunlight and moving water) that cannot be reasonably stored. Therefore, these resources are considered variable, following the availability of their primary fuel source. There are two overarching attributes of variable generation that can impact the reliability of the bulk power system if not properly addressed:

1) Variability: The output of variable generation changes according to the availability of the primary fuel resulting in fluctuations in the plant output on all time scales.

2) Uncertainty: The magnitude and timing of variable generation output is less predictable than for conventional generation.

The North American Electric Reliability Corporation (NERC) is responsible for ensuring the reliability of the bulk power system in North America. Anticipating the growth of variable generation, in December 2007, the NERC Planning and Operating Committees created the Integration of Variable Generation Task Force (IVGTF), charging it with preparing a report [1] to identify the following:

3) Technical considerations for integrating variable resources into the bulk power system

4) Specific actions, practices and requirements, including enhancements to existing or development of new reliability standards

One of the identified follow-up tasks from [1] was the need for the models for variable generation technologies. For the purpose of completeness of this document, the proposed action item Task 1-1 from [1] is repeated below.

Item #	Proposed Improvement	Abstract	Lead	Deliverables	Milestones
1.1	Standard, valid, generic, non-confidential, and public power flow and stability models (variable generation) are needed and must be developed, enabling planners to maintain bulk power system reliability	Valid, generic, non-confidential, and public standard power flow and stability (positive-sequence) models for variable generation technologies are needed. Such models should be readily validated and publicly available to power utilities and all other industry stakeholders. Model parameters should be provided by variable generation manufacturers and a common model validation standard across all technologies should be adopted. The NERC Planning Committee should undertake a review of the appropriate Modeling, Data and Analysis (MOD) Standards to ensure high levels of variable generation can be simulated. Feedback to the group working on NERC Standards' Project 2007-09 will be provided.	*Ad Hoc* group: Members from IVGTF - Planning	Make recommendations and identify changes needed to NERC's MOD Standards	• Draft report ready by December 2009 PC meeting • Final report with recommendations to PC for endorsement in February 2010 • Develop SAR with Standards Committee if required.

Therefore, the goal of this document is to address the above action item and to provide:

1. The roadmap for development of valid, generic, non-confidential, and public standard power flow and stability (positive-sequence) models for variable generation technologies. Namely, what is available at present and what is the path forward to developing and deploying these models.

2. The NERC standards implications and feedback on what further NERC action items may be needed, if any, to address model application and validation as it relates to variable generation.

Throughout this report reference is made to various forms of models (standard, generic, user-written, 3-phase, etc.). The present and imminent requirement is to have models that are standard (i.e. a defined model structure used by all commercial software tools), publicly available and not specific to any particular design (i.e. "generic" and able to reasonably represent key performance relevant to bulk power system studies) – this is the focus, which is further elaborated upon this report. The process and need for model validation, however, applies to any and all levels of modeling.

2. The Need for Models for Variable Generation

The planning and operation of large interconnected power systems in diverse regions in the North American continent, is a complex task which requires daily analysis and computer model simulations. System planners and operators use simulation studies to assess the potential impact of credible (and sometimes extreme) contingency scenarios and to assess the ability of the power system to withstand such events while remaining stable and intact (i.e., to avoid cascading outages). When a credible disturbance event is simulated in computer models of the power system and the observed result is unacceptable performance, system planners and/or operators must develop either operating strategies or planned equipment additions (e.g., line re-conductoring, addition of shunt reactive compensation devices, etc.) to mitigate the potential problem. To help ensure proper assessment of reliable performance and to minimize (as much as possible) capital investment, models are required that reasonably represent actual equipment performance in simulations.

The NERC Modeling, Data, and Analysis (MOD) Reliability Standards require Registered Entities to create procedures needed to develop, maintain and report on models to analyze the steady-state and dynamic performance of the power system (MOD-011 and MOD-013). Equipment owners are required to provide steady-state and dynamic models (MOD-012) to the Regional Entities. This information is required to build a reasonable representation of the interconnected system for planning purposes, as stated in MOD-014 and MOD-015.[3] Specifically, models are required to perform powerflow, short circuit, and stability studies necessary to ensure bulk power system reliability.

Therefore, system models are required for generation equipment at three levels:

1. Models for assessing the steady-state behavior of the units and their fault current contributions for protection system analysis.
2. Models for emulating the dynamic behavior of the units for bulk power system time-domain stability analysis.
3. Detailed, equipment-specific (3-phase) models for specialized studies.

In this chapter, the aforementioned three categories of models are described in detail focused on variable generation technologies.

[3] http://www.nerc.com/page.php?cid=2|20

2.1. Steady-State and Fault Current Analysis

Steady-state analysis in the context of bulk power system studies is primarily associated with power flow, which determines the flow of power on transmission lines and transformers and the voltages at power system nodes (substations). Accurate calculations are essential in the planning and design of the interconnected power system to ensure that all equipment will be operated within its rated capability under various credible scenarios (including contingencies). These calculations are performed under various base-case conditions (i.e., all equipment generally in service) and contingency conditions that impact one or more power system elements such as a line, generating unit, or transformers out of service (e.g., for different system load conditions including peak load, light load, different seasons, or different power transfer).

To assess the adequacy of protection system settings, faults on transmission equipment are simulated and the settings for protection relays are evaluated, as well as the calculated fault currents are compared to the current rating of circuit-breakers.

Both these analyses are critical to the reliable operation of the power system. To perform these analyses, adequate models are needed for simulating the steady-state power flow and the fault current characteristics of generation equipment.

2.2. Time-Domain Positive Sequence Dynamic Models for Bulk Power System Stability Analysis

Time-domain simulations are a key tool for assessing the reliability of the bulk power system assessing the stability of the system.[4]

> "Reliability of a power system refers to the probability of its satisfactory operation over the long run. It denotes the ability to supply adequate electric service on a nearly continuous basis, with few interruptions over an extended time period.
>
> Stability of a power system refers to the continuance of intact operation following a disturbance. It depends on the operating condition and the nature of the physical disturbance."

Similarly, NERC defines stability as, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances."[5]

[4] The definitions listed are quoted from: P. Kundur, J. Paserba, V. Ajjarapu, G. Andersson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. Van Cutsem and V. Vittal, "Definition and classification of power system stability: IEEE/CIGRE joint task force on stability terms and definitions", IEEE Transactions on Power Systems, Volume 19, Issue 3, Aug. 2004, pp: 1387 – 1401. (http://ieeexplore.ieee.org)

Stability analysis is traditionally performed using positive-sequence models. This includes models that focus on system simulation under assumed perfect balanced conditions (i.e., no imbalance in the 3-phase system voltages and currents). Furthermore, the primary stability issues that are investigated (angular stability, voltage stability, frequency control/stability) for bulk power systems tend to be bounded within a small frequency band around the system fundamental frequency. Positive sequence models are typically required to be valid in a range of roughly 0.1 Hz to about 3 Hz, with the control system having validity up to 10 to 15 Hz to allow for investigating general control loop stability. With these simplifying assumptions, it has been historically easy to establish generic, non-proprietary models for representing conventional generation and its controls. Functional models that are non-proprietary and generic (i.e., applicable to any vendors equipment, simply by changing the model parameters) are needed for the various variable generation technology. A library of models to deal with each family of variable generation technology is required to support reliability assessment. What is presently available, and what must be further developed is discussed in the next chapter.

Aside: *There are many cases were extended term analysis may be necessary, in which case wind speed variations may be a needed input to the model. For the purposes of typical stability analyses, however, where the study period spans over only several seconds, wind speed is typically assumed to be constant.*

2.3. Detailed Three-phase Equipment Level Models

There are a number of potential interaction issues that may occasionally require detailed analysis [2]. To perform this analysis, detailed three-phase equipment models are required.

Subsynchronous resonance (SSR) is a phenomenon whereby series compensation of a transmission line results in electrical resonance frequencies in the subsynchronous frequency range that can lead to destabilizing modes of mechanical torsional vibration on the turbine-generator shaft that fall in the frequency range of the electrical resonance.[6] These resonance phenomena are only of concern to generation technologies with a mechanical turbine-generator shaft that is coupled to the electrical system. Type 1, 2 and 3 Wind-Turbine Generation (WTG) may be susceptible.[7] Clearly, Type 4 (where the unit is decoupled from the electrical system) and technologies like PV have no such concerns. SSR is less likely to affect wind turbines compared

[5] Glossary of Terms Used in Reliability Standards, http://www.nerc.com/files/Glossary_2009April20.pdf, Updated April 20, 2009,

[6] P. M. Anderson, B. L. Agrawal and J. E. Van Ness, Subsynchronous Resonance in Power Systems, IEEE Press, New York, 1990.
P.M. Anderson and R. G. Farmer, Series Compensation of Power Systems, ISBN 1-888747-01-3, 1996

[7] See Appendix I for more information on these WTG configurations.

to large conventional synchronous generators since the typical torsional mode for a wind turbine is quite low (around 1 to 4 Hz). Accordingly, it would be quite unlikely that the level of series compensation in a system would be high enough to result in an electrical resonance that would interact with a low mechanical frequency.[8] A larger concern is induction machine self-excitation.[9] Some detailed 3-phase analysis and discussions with the wind turbine manufacturer on a case by case basis is prudent when installing wind near series compensated lines.

Another potential phenomenon related to torsional mechanical modes is device dependant subsynchronous oscillations, often referred to in the literature as subsynchronous torsional interaction (SSTI). This was first observed at the Square Butte HVDC project in 1976.[10] SSTI is a phenomenon by which controls associated with power electronic based transmission equipment (e.g., SVC or HVDC) may introduce negative damping torques in the frequency range associated with the torsional mechanical modes of oscillation of nearby thermal turbine-generating units. Again, due to the relatively low frequency range for torsional modes of wind turbine, this may not be a concern in most cases; however, where wind plants are closely coupled to a HVDC system, analysis is prudent to ensure that control and/or torsional interaction do not occur. This analysis will typically require detailed three-phase models for both the wind plant and the HVDC system. Also, SSTI is not necessarily detrimental[11] because, in some cases, torsional damping can be markedly improved through the application of power electronic devices. One thermal power plant in the Western U.S. grid uses a dedicated SVC for this purpose as a means of mitigating the effects of SSR. [12] A practical example of this is the Taiban Mesa wind plant located in New Mexico. This wind plant is located electrically adjacent to a back-to-back HVDC station – Blackwater. The detailed interconnection studies performed by ABB during the design of the wind plant showed that there was little risk of torsional interaction between the HVDC controls and the wind turbine generators. This analysis required detailed equipment level (3-phase) models of the wind turbines, the HVDC and transmission network.

[8] Note: The electrical resonance needs to be in the range of 56 to 59 Hz on a 60 Hz system found in North America.

[9] P.M. Anderson and R. G. Farmer, Series Compensation of Power Systems, ISBN 1-888747-01-3, 1996
C. F. Wagner, "Self-Excitation of Induction Motors with Series Capacitors", AIEE Transactions, pp.1241-1247, Vol. 60, 1941. (http://ieeexplore.ieee.org)

[10] M. Bahrman, E. Larsen, R. Piwko, H. Patel, "Experience with HVDC – Turbine Generator Torsional Interaction at Square Butte", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-99, pp. 966-975, May/June 1980. (http://ieeexplore.ieee.org)

[11] D. Dickmander, P. Pourbeik, T. Tulkiewicz and Y. Jiang-Häfner, "SSTI Characteristics of HVDC Light", White paper by ABB Inc., December, 2003

[12] Pourbeik, A. Boström and B. Ray, "Modeling and Application Studies for a Modern Static VAr System Installation", IEEE Transactions on Power Delivery, Vol. 21, No. 1, January 2006, pp. 368-377. (http://ieeexplore.ieee.org)

Other phenomena that may expose the shaft of a WTG to cyclical and significant transient torque pulsations may also be a concern. For example, nearby arc furnaces, or high-speed re-closing on a transmission line emanating from the wind plant substation, or repeated commutation failures on a nearby conventional line-commutated HVDC. As a first step, some simple transient stability analysis may be performed to estimate the expected step change in the electrical torque on a wind turbine generator due to the electrical event, and the wind turbine manufacturer consulted to identify if the observed level of transient torque is a concern. Based on consultation with the wind turbine manufacturer, more detailed analysis may be required to assess if a potential problem exists and how it may be remedied.

Another issue that may be of concern is the stability and behavior of variable generators in extremely weak short-circuit nodes of the power system and regions of the system that may be highly susceptible to islanding. Again, more detailed models than positive sequence stability representations may be needed to study these scenarios (e.g., to accurately review the potential for temporary over voltages upon islanding, etc.). Also, in some cases and designs (e.g., Type 3 WTG), the behavior of the unit as it pertains to voltage-ride through during fault scenarios can be more onerous on the controls (i.e., controlling the DC bus voltage in the Type 3 WTG) for unbalanced fault scenarios as opposed to a balance 3-phase faults. Thus, 3-phase detailed equipment models are needed to assess these phenomena.

Finally, transient stability studies should be completed to ensure that basic control loops in the variable generation plants (e.g., central voltage control systems often deployed in doubly-fed and full-converter based wind plants that regulate voltage at the interconnecting substation by adjusting the reactive output of all wind turbines in the wind plant) do not interact or interfere with other nearby transmission and generation controls. This often requires proper tuning of the controls.

This brief section illustrates the need for the availability of detailed 3-phase equipment level models, which cannot be generic. These models are likely to be proprietary and may need to be used under non-disclosure agreements between the vendor and the plant developer/utility. Therefore, it is important to recognize the need for these models so that they are developed and available to be easily deployed and used when such specialized studies are needed.

2.4. Summary

This chapter has outlined the basic power generation plants models required power system analysis related to reliability assessment. In addition, these models need to be generic (i.e., the model structure applicable to any vendor's equipment, with only the variation of the model parameters to represent various vendor equipment) and non-proprietary (i.e., publicly available to all stakeholders). Adequate models readily exist for conventional synchronous generators, but, until recently, have been unavailable for any variable generation technology. In the next chapter the current status of models for all variable generation technologies is discussed.

3. Present Status of Modeling Variable Generation

This chapter provides an overview of the models and modeling capability presently available. In the summary of this chapter the gaps are identified and areas requiring further work are identified. The modeling and model development discussed here is primarily for power system power flow, short-circuit and stability analysis.

Time-domain stability analysis is concerned with phenomena in the tens of milliseconds to several minutes time frame (see Figure 3.1).

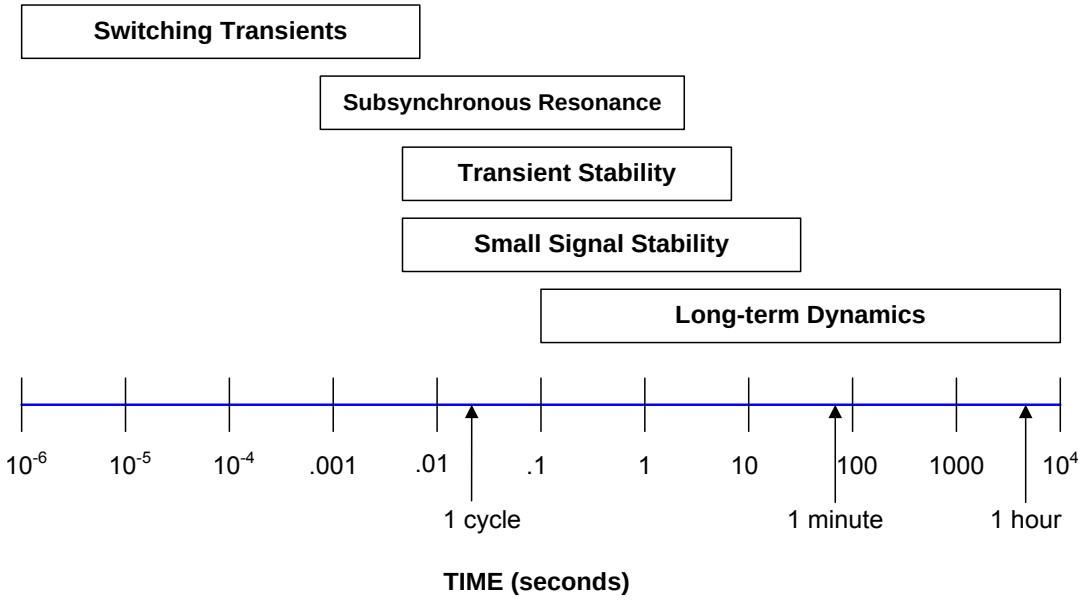


Figure 3.1: Times of various phenomena of interest in power system studies (GE).

3.1. Wind Generation

3.1.1 WECC/IEEE Effort for Generic Models

The size of individual WTGs has increased dramatically from several hundred kilowatts to multi-megawatt turbines. The size of individual wind power plants has also increased significantly. In the past, a typical wind power plant consisted of several turbines. Presently, wind power plants

of several 100 MW and larger are being proposed. By some projections,[13] as much as 300 GW (20% penetration) of wind generation capacity is forecast in the U.S. by 2030 and NERC projects an increase of 229 GW of new wind generation installed capacity by 2018.[14] The increased penetration of renewable energy generation poses significant questions concerning the ability of the power system to maintain reliable operation.

Presently, most wind turbine technologies use power electronics and advanced reactive power compensation as an integral part of wind turbine generator and wind power plant. Under dynamic transients, the behavior of modern wind turbines must be accurately simulated to predict the response of the wind power plant. Misrepresentation of WTGs in transmission studies may threaten the reliability of power systems by either resulting in excessive overbuild of transmission systems due to pessimistic models, or in deficient transmission system investment based on optimistic models.

Turbine manufacturers have developed dynamic models for their wind turbines. These dynamic models are typically user-written models in commercially available power system simulation software platforms (e.g., Siemens PTI PSS™E, GE PSLF™, DigSILENT PowerFactory, etc.). Detailed three-phase equipment level models of WTGs used for internal design purposes are also often developed by manufacturers in either their own simulation platforms or commercial software tools including PSCAD® or Matlab® Simulink.

Unfortunately, both these categories of models (the user-written positive-sequence models and the three-phase detailed equipment models) require significant input data/parameters considered to be proprietary by the turbine manufacturers and therefore are not freely available to the general public. Access to these models usually requires a non-disclosure agreement (NDA) between the dynamic model user and the turbine manufacturers. This agreement is only valid for a specific turbine model, for a given period of time.

In many cases, it takes months to negotiate and to finalize the NDA. Furthermore, in some cases there are incompatibilities among turbine models developed by different turbine manufacturers which results in numerical interactions if multiple user-written models are incorporated into a single power system model for system analysis. This makes the work of power system planners almost impossible. The NDA are also usually bilateral, which renders it impossible to share the information among the manufacturers to help resolve incompatibility problems. Finally, the NDAs make it difficult, at best, and impossible, in some cases, to share the models thereby potentially violating the NERC requirements for submitting models for system planning studies.

[13] http://www.nrel.gov/docs/fy07osti/40482.pdf
[14] http://www.nerc.com/files/2009_LTRA.pdf

With this back drop, the WECC Wind Generator Modeling Group (WGMG) initiated the development of generic wind turbine models of the four (4) different types of wind turbines (see Appendix I for these four WTG designs). These four types of turbines currently hold the largest market share throughout the world. WECC is interested in providing accurate and validated models of standard wind turbines that will be available in their database, including the datasets to be used for testing the models, and the methods for representing a wind power plant in power system studies. These goals are being accomplished through the development and validation of standard models. The standard models must be generic in nature – that is, they must not require nor reveal proprietary data from the turbine manufacturers. These improved standard (generic, non-proprietary) dynamic models enable planners, operators and engineers to perform the necessary transmission planning studies required to ensure system reliability.

Currently, the first generation of these generic WTG models, for all four turbines types, have been developed and are available as part of the main model library for the two most widely used commercial power system simulation tools in North America (i.e., Siemens PTI PSS™E, GE PSLF™)[15]. As a continuation of, and in parallel with, the WECC effort, the Institute of Electronic and Electrical Engineers (IEEE), Power & Energy Society (PES) has also established a Working Group to investigate WTG modeling issues: The IEEE Working Group on Dynamic Performance of Wind Power Generation, under the Power System Dynamic Performance Committee. This Working Group is actively expanding the efforts of generic dynamic modeling for wind power plants, focusing on modeling specifications, disseminating methods and model validation.

To date, the first generation of generic models developed and released have focused on capturing the response of the units to electrical voltage disturbances on the transmission grid (grid faults). One deficiency, particularly for the Type 1 and 2 models, is the proper representation of unit responses to large system frequency excursions. These models have not been verified due to the lack of data on actual turbine behavior under such circumstances and will require further development, in consultation with turbine manufacturers.

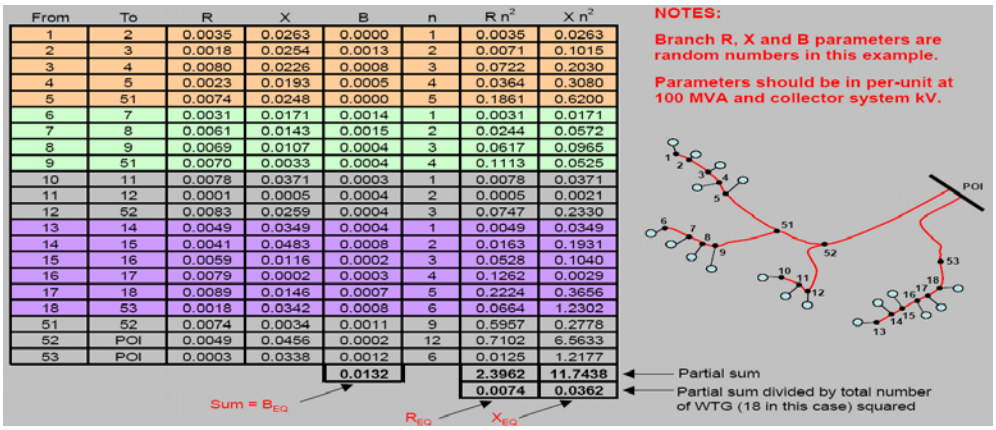
Finally, as with all modeling exercises, model development and validation are iterative processes, requiring:

- Generic wind turbine models are to be made available to the public.

[15] PSS®E-32.0 Program Application Guide: Volume II, Chapter 21.
PSS®E-32.0 Model Library, Chapters 17 through 21
GE PSLF User's Manual. v.17.0_04. October, 2009.

- Generic wind turbine models must be validated before release and public dissemination, which is being pursued in WECC, IEEE, International Electrotechnical Commission (IEC) and other forums.
- Models should evolve and be revalidated as the technology progresses.
- Data from field measurement and monitoring for model validation can be a vital resource.

A somewhat unique need in modeling variable generation (e.g., wind) is the need for methods required to develop equivalent models for large wind power plant. In contrast to conventional fossil fuel and hydro power plants, where plants are constituted by either a single large unit or, at most, a few large units, a wind power plant can be made up of tens to more than a hundred WTGs. For large scale power system simulations, particularly in North America where the power system models are quite large, it is often preferred to reduce the wind power plant to a single equivalent unit. Accordingly, techniques are needed for model aggregation and testing their validity – some significant progress has been made in this regard. For example, Figure 3.2 shows the technique developed for reducing the impedance of the wind power plant collector system into a single, equivalent feeder impedance for representation of the wind power plant (WPP) by an aggregated single equivalent unit in power system studies.



From	To	R	X	B	n	R n²	X n²
1	2	0.0035	0.0263	0.0000	1	0.0035	0.0263
2	3	0.0018	0.0254	0.0013	2	0.0071	0.1015
3	4	0.0080	0.0226	0.0008	3	0.0722	0.2030
4	5	0.0023	0.0193	0.0005	4	0.0364	0.3080
5	51	0.0074	0.0248	0.0000	5	0.1861	0.6200
6	7	0.0031	0.0171	0.0014	1	0.0031	0.0171
7	8	0.0061	0.0143	0.0015	2	0.0244	0.0572
8	9	0.0069	0.0107	0.0004	3	0.0617	0.0965
9	51	0.0070	0.0033	0.0004	4	0.1113	0.0525
10	11	0.0078	0.0371	0.0003	1	0.0078	0.0371
11	12	0.0001	0.0005	0.0004	2	0.0005	0.0021
12	52	0.0083	0.0259	0.0004	3	0.0747	0.2330
13	14	0.0049	0.0349	0.0004	1	0.0049	0.0349
14	15	0.0041	0.0483	0.0008	2	0.0163	0.1931
15	16	0.0059	0.0116	0.0002	3	0.0528	0.1040
16	17	0.0079	0.0002	0.0003	4	0.1262	0.0029
17	18	0.0089	0.0146	0.0007	5	0.2224	0.3656
18	53	0.0018	0.0342	0.0008	6	0.0664	1.2302
51	52	0.0074	0.0034	0.0011	9	0.5957	0.2778
52	POI	0.0049	0.0456	0.0002	12	0.7102	6.5633
53	POI	0.0003	0.0338	0.0012	6	0.0125	1.2177
				0.0132		2.3962	11.7438
						0.0074	0.0362

Figure 3.2: Example shows the method for reducing the impedance of a wind power plant collector system into a single equivalent impendence.[16]

[16] "WECC Wind Generator Power Flow Modeling Guide" (http://www.wecc.biz/library/WECC%20Documents/Documents%20for%20Generators/Generator%20Testing%20Program/Wind%20Generator%20Power%20Flow%20Modeling%20Guide.pdf)

Figure 3.3 shows an example for dynamic simulations of aggregating the WPP into a single equivalent unit and an equivalent single impedance representing the entire collector system as compared to a detailed model representing the whole WPP unit-by-unit – the example shown assumes that all WTGs in the WPP are identical, in cases where this is not true multiple equivalent units may be needed one for each WTG type. As can be seen in this figure, the results from the two simulations compare very well at the point of interconnection (which is what is shown); thus, the equivalent aggregate is adequate for power system studies.[17]

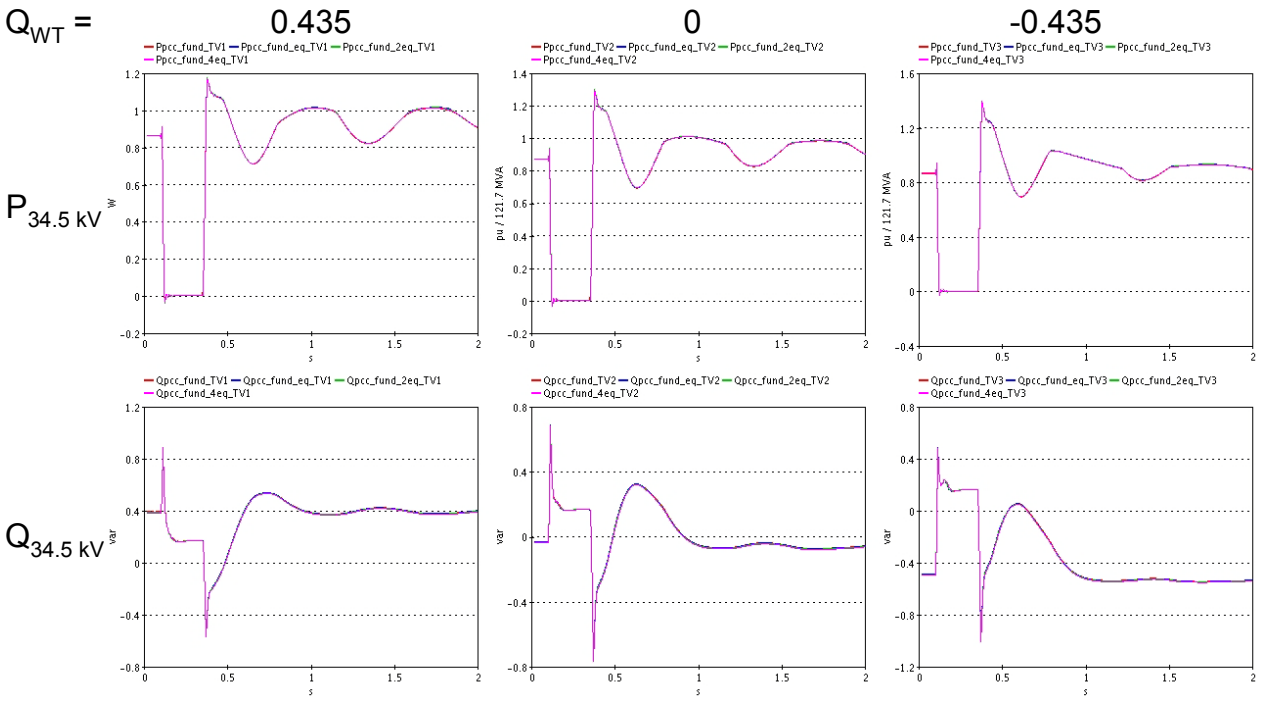


Figure 3.3: Example of time-domain simulations comparing a detailed model of a Wind Power Plant (i.e., representing the complete collector system and each WTG individually), versus a single-machine equivalent aggregate (i.e. the entire plant is represented by one equivalent unit and an equivalent impedance to represent the whole collector system).

[17] Figure is from J. Brochu, R. Gagnon and C. Larose, "Validation of the WECC Single-Machine Equivalent Power Plant", Presented at the IEEE PES DPWPG-WG Meeting at IEEE PSCE, March 2009.

3.1.2 UWIG Generic Model Documentation and Validation Effort

The Utility Wind Integration Group (UWIG),[18] under a U.S. Department of Energy grant, will be launching an effort to provide the basic documentation, application, and validation of generic models for wind turbines. The goal of this project is to accelerate the appropriate use of generic wind turbine models for transmission network analysis.

The objectives of the project, which will commence in early 2010 and run for a period of two years, are to:

- Complete characterization and documentation of the four generic models developed through an outgrowth of a WECC activity begun in 2005;
- Defining proposed enhancements to the generic wind turbine model structures that would allow representation of more advanced features including power control, automatic curtailment, inertial and governor response;
- Comparative testing of the generic models against more detailed (and sometimes proprietary) versions developed by turbine vendors;
- Developing recommended parameters for the generic models to best mimic the performance of specific commercial wind turbines;
- Documenting results of the comparative simulations in an application guide for users;
- Acquiring test data from all available sources for the purpose of validating the performance of the appropriately specified generic models in actual case studies;
- Conducting technology transfer activities in regional workshops for dissemination of knowledge and information gained, and to engage electric power and wind industry personnel in the project while underway.

[18] The UWIG was established in 1989 to provide a forum for the critical analysis of wind technology for utility applications and to serve as a source of credible information on the status of wind technology and deployment. The group's mission is to accelerate the development and application of good engineering and operational practices supporting the appropriate integration of wind power into the electric system. It currently has more than 150 members spanning the United States, Canada, and around the world including investor-owned, public power, and rural electric cooperative utilities; transmission system operators; and associate member corporate, government, and academic organizations http://www.uwig.org/aboutuwig.htm

Maintaining communication and coordination with other ongoing activities and agencies engaged in this topic is another objective of the effort which will be critical for success.

3.1.3 IEC Effort for Generic Models

The International Electrotechnical Commission (IEC) recently started a Working Group in October 2009 to address the development of generic and "standard" models for wind turbine generators.[19] The goal of this Working Group is to define standard dynamic simulation models for wind turbines and wind plants, which are intended for use in power system and grid stability analyses, and should be applicable for dynamic simulations of power system events including short circuits (low voltage ride through), loss of generation or loads, and system separation. The group is approaching this work in two parts. Part 1 will focus on specifying dynamic simulation models for the generic wind turbine topologies/concepts/configurations presently in the market, as well as specifying how these models may be modified as future technologies/concepts are introduced. The standard should also include procedures for validation of the models specified. Another goal is that the models should be developed and specified at a fundamental level so they are independent of any specific software platform and can be adopted by any software vendor.

Part 2 of this work will be focused on extending the modeling to allow for modeling of the entire wind power plant, including wind power plant control and auxiliary equipment.

Several members of this IEC Working Group are also members of the WECC and IEEE Working Groups (and this NERC Task Force). The three groups are clearly working in close collaboration to ensure maximum benefit to the industry globally and maximum sharing of knowledge already gained through the WECC and IEEE efforts.

[19] http://www.iec.ch/dyn/www/f?p=102:14:0::::FSP_ORG_ID:5613

3.2. Photovoltaic Solar Generation

Photovoltaic (PV) systems for power generation are quickly increasing becoming a significant portion of generation in some regions in North America. PV or solar arrays are composed of a large number of solar cells connected in series and parallel. These cells produce a DC voltage when they are exposed to sunlight due to the photo-voltaic effect[20]. Figure 3.4 shows the I-V characteristics of a cell at a constant temperature and various sun intensity or *insolation* levels.

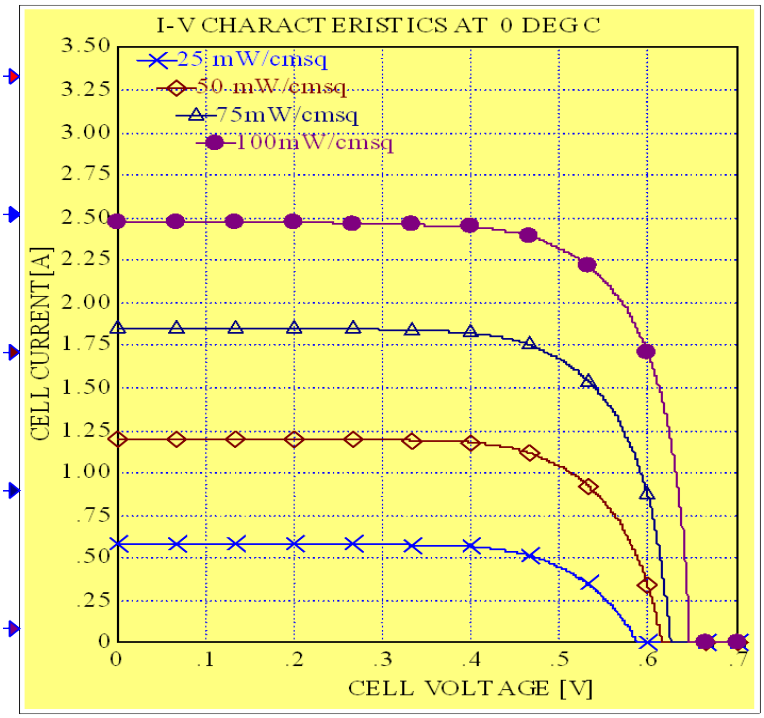


Figure 3.4: Current-Voltage characteristics of a solar cell for various insolation levels at a constant temperature (source [11][21]).

[20] The photo-voltaic effect is the process by which an electric potential difference (voltage) is created in a material exposed to light (electromagnetic radiation), which then leads to the flow of electric current. This process is directly related to the photo-electric effect, but distinct from it in that in the case of the photo-electric effect electrons are ejected from the material surface upon being exposed to high enough frequency (energy) light, whereas in the photo-voltaic effect the generated electrons are transferred across a material junction (e.g., PN junction in a photo-diode) resulting in the buildup of a voltage between two electrodes and the flow of direct current electricity.

[21] Solar Radiation Research Laboratory at the National Renewable Energy Laboratory (http://www.nrel.gov/midc/srrl_rsp/)

Figure 3.5 shows that the current is limited when the cell is short-circuited (Voltage=0).

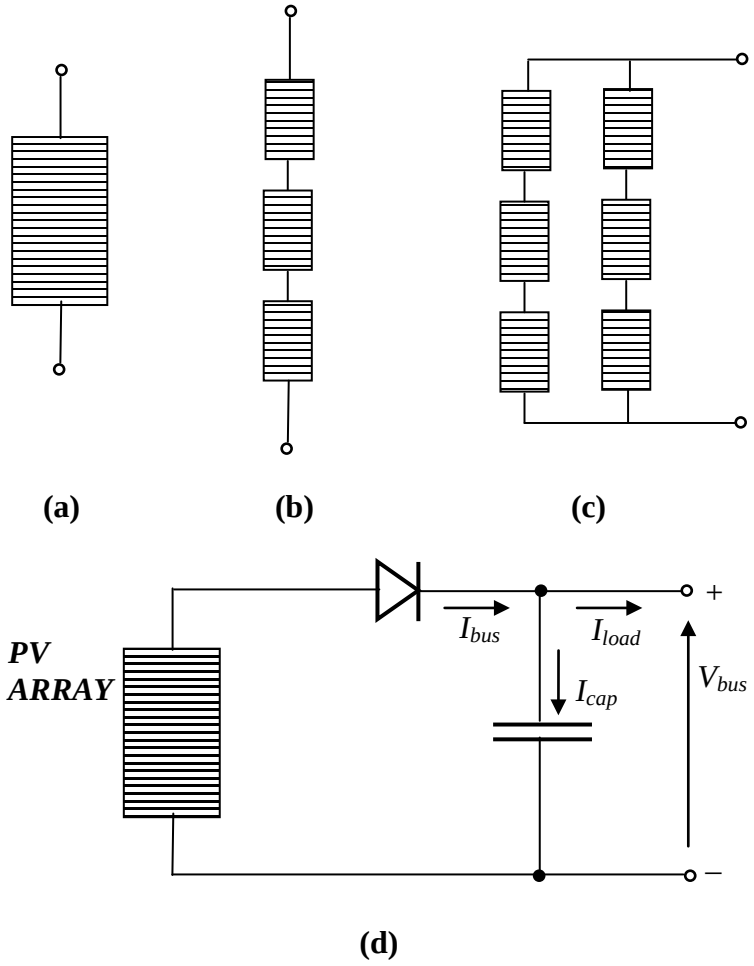


Figure 3.5: The concept of a solar array: (a) a single solar cell, (b) a series connection of solar cells (N_{ser} = 3 and N_{par} = 1), and (c) a solar array (N_{ser} = 3 and N_{par} = 2). The solar cell array(s) is then connected to a DC bus (d).

Figure 3.5 shows the concept of the solar cell up to the solar array. To use the DC power generated by the PV array in an AC power system, the DC power must be converted to 60 Hz AC in North America (50 Hz in some other regions in the world, like Europe). There are several power electronic based converter concepts that can achieve this, which can be classified into two general categories: line-commutated converters (LCC) and self-commutated or more commonly

referred to as voltage-source converters (VSC). These technologies have been applied for decades and are well understood. LCC use thyristors as their controlled switching device. The switching on of a thyristors can be controlled, while the turn-off time cannot be controlled and happens at the next AC waveform current zero crossing. LCC systems must be operated in a network with an AC source and cannot operate to serve an isolated load. In contrast, VSC systems are self-commutating, that is the power electronic switching devices used (e.g., integrated gate-commutated thyristors or IGCTs and insulated-gate bipolar transistors or IGBTs) are able to be completely controlled for both turn-on and turn-off and allow the VSC to completely control the AC waveform produced and adjust the power factor as seen on the AC side to within the current rating of the device. Due to advances in the technology, most power electronic converters employed in PV systems are of the VSC type.[22]

From a modeling standpoint for power system studies, there are some user-written manufacturer-specific models in existence as developed by various PV manufacturers. Presently, no generic or standard models exist.

The WECC Working Group, which has been addressing the development of generic WTG models, will be extending its effort in 2010 to review developing generic PV models for dynamic simulations in stability studies. As a starting point, the grid side structure of the Type 4 WTG model may be used since it represents a VSC. This is because PV is typically connected to the grid with a VSC and it will behave electrically similar to a Type 4 WTG that has a similar electrical interface with the grid—this is from a grid perspective looking at the electric response and neglects any of the effects of the energy source.

From a steady-state, power flow and short-circuit analysis perspective, the behavior of the PV technologies will behave in a similar fashion to a Type 4 WTG because of the VSC interface, and because its power factor can be controlled based on the control functionality of the VSC design. Its short-circuit response will be limited to the current limit effected by the VSC under grid fault conditions.

The development of generic and standard PV models is presently a topic for further research. This should be pursued imminently and much of what has been learnt from the WTG model development process should be leveraged.

[22] IEA-PVPS: Grid-Connected Photovoltaic Power Systems: Survey of Inverter and related Protection Equipment; Report IEA PVPS T5-05: 2002, December 2002 (http://www.iea-pvps.org/products/download/rep5_05.pdf).

3.3. Solar Thermal

Solar thermal energy is based on harnessing the radiated heat of the sun for the purpose of producing electricity. In broad terms, there are presently two main ways of achieving this:

1. Concentrating Solar Power (CSP) plants – in this case solar radiation is typically collected through a large number of mirrors (thus a large amount of solar radiation) which is then focused on a small area – the mirrors have tracking systems to follow the Sun. The concentrated solar radiation heats a high temperature working fluid, which then feeds a conventional steam-turbine generator. From an electrical grid perspective, the models needed to simulate the steady-state, short-circuit and transient time-domain dynamics of such a generating unit, are typically no different than standard synchronous generating units for fossil fuel plants.

2. The Stirling Engine concept[23] – in this design a parabolic mirror assembly concentrates the collected solar radiation on a sterling engine that sits at the focal point of the mirror assembly. A Stirling engine is a reciprocating heat engine that operates based on the concept of cyclical compression and expansion of a working fluid. As the working fluid expands/contracts it drives a piston that then turns a generator. The engine is connected to an electrical generator that produces electric energy. Once again for power system studies the units may be modeled using standard generator models. However, in this case a power plant would be constituted by a large number of small units (the typical Stirling engine is about 25 kW) in a large electrical collector system that collects the power and injects it into the utility grid – much like the collector system of a wind power plant. Thus, modeling the collector system (e.g. see Figure 3.2 for an aggregate model of a wind collector system) and any other devices in the collector system, such as shunt reactive devices etc. must be properly modeled

3.4. Tidal Generation

Tidal power generation derives energy directly from the motion of oceanic tides. The gravitational pull of the Moon and Sun, combined with the Earth's rotation result in the generation of tides. Tides generally occur with a period of roughly twelve hours, and so most coastal areas experience two high and two low tides within every twenty-four hour period. Tidal generation uses this phenomenon to generate energy. Clearly, the stronger the tides are, either in tidal current velocity or the height/level of water, the greater the potential amount of energy generation.

[23] http://www.stirlingenergy.com/ Y. Zhang and B. Osborn, "Solar Dish-Stirling Power Plants and Related Grid Interconnection Issues", *IEEE PES General Meeting*, 24-28 June 2007.

Presently, in North America tidal power is not a significant source of power in any region. Some pilot programs exist for introducing the technology. In April 2009, one was announced in Snohomish County Public Utility District in Washington State.[24]

There are several options for harnessing tidal power. One method is the use of turbines similar to wind turbines; however the fluid (water) is much denser and requires a turbine with smaller and bulkier blades, as shown in Figure 3.6. Most of these technologies typically use AC/DC/AC converter technology, similar to a Type 4 wind turbine, to convert the low frequency generated electricity to grid frequency AC electricity and interface with the power system. Once this technology becomes more prevalent a starting point for development of a suitable model structure may be the Type 4 generic wind turbine models. Understandably, the energy source characteristics are quite different from wind power and significantly more predictable.

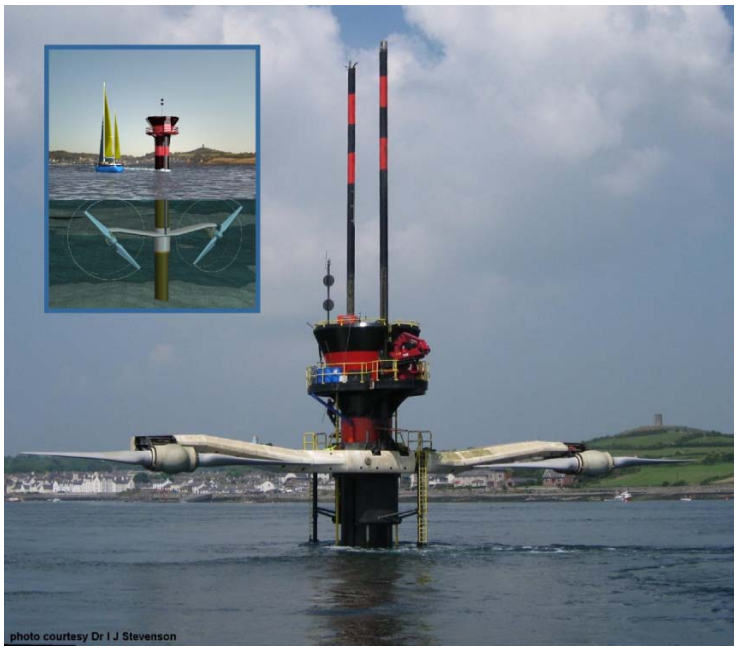


Figure 3.6: One of the many concepts for tidal generation systems (courtesy of Marine Current Turbines Limited, www.marineturbines.com).

3.5. Other Resources

There are several other emerging technologies and there are many complementary technologies (i.e., auxiliary to the variable generation resources, but designed to help with their integration into the grid) including smoothly-controlled dynamic reactive devices (static VAr systems),

[24] http://www.snopud.com/PowerSupply/tidal/tidalpress.ashx?p=1516&756_na=46

energy storage technologies etc. With respect to static VAr systems (SVCs and STATCOMs), there is an active WECC working group imminently addressing the issue of generic models for these devices.[25] The group has made substantial progress with the models defined and developed, but currently undergoing testing and validation. With regards to the other emerging technologies, most tend to be power converter based (i.e., connected to the grid through a back-to-back frequency converter) and so their electrical behavior (neglecting the characteristics of the energy source) will be similar to Type 4 wind turbines. Until these technologies mature, the basic structure of other more mature converter based generation technologies can be a good starting point.

3.6. Summary

This section has briefly presented the various types of variable generation and the present status of models and model development for power system studies. Wind generation technologies, being the most prevalent world-wide, have the most mature models. Through efforts started by WECC and being continued by IEEE and IEC, generic standard models for the four main types of WTG technologies are being developed. The first generation of these models has been released in two power system simulation software platforms most commonly used in North America. Other emerging technologies (e.g., PV, tidal power, etc.) can build on this effort to start developing generic models. For example, the WECC effort will be extending its scope in 2010 to look at PV model.

From a NERC perspective the key items are:

1. To emphasize and support efforts by WECC, IEEE and IEC to develop and standardize generic models for these technologies for power system planning studies.
2. To encourage manufacturers to familiarize themselves with the generic models being developed and be willing an able to supply parameters for these generic models to reasonably represent their equipment for power system stability studies. As highlighted in Chapter 2, more detailed manufacturer specific models may be needed in special cases and for specialized studies.
3. To encourage efforts aimed at model validation.
4. To consider any augmentation or additions to reliability standards related to Modeling, Data and Analysis (MOD) with respect to modeling and model validation of variable generation. This is discussed in greater detail in section 5 of this report.

[25] http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/MVWG/SVCTF/default.aspx

4. Present Status of Model Validation

This chapter gives an overview of the model validation work that has been done hitherto as it relates to models for variable generation. Necessarily, the primary focus of this section is on wind turbine generator models, since models for this resource are presently the most mature.

4.1. What is Model Validation?

Any and all models of a dynamic system always have limitations associated with them. A model is a representation of reality; it is an emulation – that is why it is called a model. In developing a model first the question is asked as to the specified use of the model and the conditions it must reasonably emulate – this forms the basis of a model specification from which a model is developed. The developed model establishes a certain structure with parameters, which are adjustable in order to emulate different types of equipment or design of the modeled device. Thus, valid parameterization of the model to represent a particular manufacturer's equipment is essential to support the particular scenarios to be analyzed.

Model validation is often achieved through some form of testing, either in a laboratory/factory or in field. There is a range of reasons for conducting tests for wind generation. Each test has a unique set of objectives guiding the design of adequate testing practices.

- Performance Compliance: Compliance to contractual requirements and grid codes are one reason to perform tests. Interconnection requirements (usually included in plant Power Purchase Agreements and Interconnection Contracts) and grid codes typically outline specific technical criteria that must be met to allow a power plant to connect and operate on the grid. Since these criteria point out specific levels to be met, (for example, voltage, power factor, and response time) tests may be designed with binary "pass/fail" objectives.

- Model Validation: In much of the world, power plants above a pre-defined size must be accurately represented with a dynamic simulation model used in stability analysis for operations and planning purposes. As variable generation sources such as WPP are growing in size, it is becoming increasingly important to have accurate variable generation specific models. Tests may be performed to tune and verify simulation models to closely match the performance of actual equipment. In the western U.S. and Canada, WECC has mandated that any plant with 20 MVA aggregate generation must be tested for model validation, including large wind power plants. For North America, the imminent NERC MOD-026 standard presently under development will enforce model validation requirements throughout the North American region.

To achieve the goals of model validation, there are three categories of tests that may be performed:

- Type Tests: These are tests performed by the manufacturer or independent third-parties of representative equipment. The intent is to demonstrate that a particular design of equipment exhibits specific performance, and all other equipment of that same design is assumed to have the same performance. Type tests can be:
    - *Component:* Performed on specific functions or features in a power plant or generation equipment. This could be, for example, testing the fault ride-through capability or reactive capability of a WTG, where testing is performed at the component level.
    - *Factory:* A systemic test of a major assembly (i.e., a drive train) or entire turbine-generator is performed under a controlled environment like a manufacturing facility to verify performance and validate assembly design.
    - *Unit:* A systemic test of multiple components operating together (i.e., as entire operating WTG or WPP) with the specific intent of benchmarking a model or design as a type test. For example, tests performed in Europe under the WindTest program.
- Field Tests[26]: Tests performed by the power plant asset owner, developer, host utility, manufacturer and/or independent third-parties of specific operating equipment. These tests are to demonstrate that a particular implementation, design and installation of equipment exhibit specific performance.
    - *Commissioning:* Tests performed on new equipment entering its period of commercial operation service.
    - *Periodic Maintenance or Calibration:* Tests performed periodically after the plant is in commercial operation to verify that equipment continues to perform as well as it did during commissioning.

[26] See for example: WSCC Control Work Group and Modeling & Validation Work Group, "Test Guidelines for Synchronous Unit Dynamic Testing and Model Validation", February 1997. (www.wecc.biz), and IEEE Task Force on Generator Model Validation Testing, "Guidelines for Generator Stability Model Validation Testing", Proceedings of the IEEE PES General Meeting, Tampa, FL, June 2007 (http://ieeexplore.ieee.org)

- *Periodic Model Validation:* Tests performed periodically after the plant is in commercial operation to verify that simulation models adequately represent actual plant performance (for example, the periodic model validation testing required by WECC).
- *Periodic Codes & Standards Validation:* Tests performed periodically after the plant is in commercial operation to benchmark and validate plant performance per contractual requirements. These tests are typically performed to obtain a permanent operating license for the power plant.

- On-Line Monitoring[27]: Other information of interest is from continuous data gathering based on ongoing performance of an operating power plant. Data collected from external and unscheduled events, including grid disturbances or in the case of WTG large changes in wind is particularly useful. Monitoring also benchmarks performance under normal operation.

With these general concepts in mind, the following subsections present some example cases studies of model validation and validation approaches for variable generation sources. The examples emphasize WPP and WTG, since wind generation is the present dominant variable generator sources in the North America continent.

4.2. Examples of Model Validation Efforts

4.2.1 Hydro- Québec Example

The province of Québec has vast wind energy potential. Though wind energy generation in 2009 accounts for nearly 1.3% of the total installed capacity in the Québec control area, the penetration rate of wind energy generation will reach 10% by 2015. A total capacity of 528 MW is currently in operation and approximately 3,000 MW are under development. Five wind turbine manufacturers will supply the WTGs for the different projects under study.

The configuration of the Hydro-Québec transmission system is essentially radial. Approximately 85% of the total installed generation feeding the system is located at distances up to 1,300 km

[27] See for example: P. Pourbeik, "Automated Parameter Derivation for Power Plant Models From System Disturbance Data", Proceedings of the IEEE PES General Meeting, Calgary, Canada, July 2009 (http://ieeexplore.ieee.org). This reference shows actual application of on-line disturbance monitoring to power plant model validation for conventional fossil fuel generation. It may be feasible to apply similar algorithms and approaches for continuous re-validation of WTG and other variable generation technologies once generic standard models have been developed. This is a current topic for research.

from the closest major load centers. With this configuration, the system transfer capability is mainly limited by stability constraints (transient stability and voltage stability) rather than congestion or thermal capacity of equipment; hence the need for reliable models for wind power plants and all other generation.

Stability studies are critical to determine the compensation equipment required to maintain the reliability of the power system when integrating new generation. They are also essential for operation planning studies including control system design and tuning and determination of transfer capabilities.

So far, Hydro-Québec has faced two major difficulties regarding user-written models provided by the wind turbine manufacturers. First, models often lack robustness and do not represent accurately some important features (convergence problems in low short-circuit network, do not take into account frequency excursions, do not represent secondary voltage regulation, etc.). Second, model validation by the manufacturers is often incomplete, not available, or difficult to translate to real projects (different settings or software versions, design of the collector system, etc.). In some cases, these difficulties have lead Hydro-Québec to build its own models (see Hypersim section below).

General validation test program

Since 2006, Hydro-Québec has performed validation tests on WPP connected to its transmission system and a general validation test program was established in 2009.[28] The power producer has the obligation to perform validation tests in order to demonstrate that its facilities meet the Transmission Provider requirements. The purposes of this program are:

1. To demonstrate that WPP meet the Transmission Provider technical requirements related to wind generation;
2. To validate numerical models and parameters associated with the WPP, specifically those given to the Transmission Provider by the power producer, by comparing the model response to recordings taken during field tests;
3. To confirm the electrical data of power producer facilities.

The validation program is divided into seven functions to be validated:

1. Primary voltage regulation

[28] http://www.hydroquebec.com/transenergie/fr/commerce/pop_raccordement_transport.html

2. Undervoltage response (LVRT)
3. Inertial response
4. Secondary voltage regulation
5. Power factor
6. Maximum ramp rates
7. Power quality

The tests for the primary voltage regulation are performed on a single WTG and consist in producing instantaneous voltage variations of low amplitude on the terminal of the WTG and small voltage steps of limited duration injected directly into the WTG voltage control system. Three-phase voltages and currents are recorded at the wind generator to measure the local dynamic response of a wind generator to a rapid voltage change and to verify that the response meets voltage regulation requirements. The results are also used to set the model parameters (time constant and gain) used in dynamic simulations. The tests regarding the secondary voltage regulation are similar but are conducted for the entire power plant.

The validation test program includes LVRT tests on one generating unit to verify that requirements during undervoltage conditions are met. The power producer has the responsibility to conduct the tests or to provide a complete report describing tests performed on an identical generating unit (same software version) to demonstrate that the requirements are met. So far, no LVRT tests were performed on site on WPP integrated on the Hydro-Québec network. However, monitoring equipment has been installed at three locations in wind plants: at their point of interconnection, on a 34.5 kV feeder of the collector system and on one generating unit. The monitoring system records signals either continuously or upon detecting variations occurring at the point of interconnection: active power variations, voltage sags and swells and system frequency excursions. These signals are primarily voltages and currents but may also be mechanical variables or other signals.

The field recordings recorded on the network can thereafter be used to validate the dynamic response of the models. This is a time consuming effort that requires the collaboration of the manufacturers to modify the models if necessary. Event recordings to-date have made possible suitable validation of two Hydro-Québec Siemens PTI PSS®E models and one ElectroMagnetic Transients Program (EMTP) model.

Inertial response requirements were not in defined for the projects started before 2005. Consequently, existing wind plants do not have to fulfill them. However, the requirements have to be met for WPP to be commissioned in 2011 and after. The corresponding validation tests consist in emulated frequency steps and ramps of limited duration. Besides verifying the

requirements, the test results will be used to validate the parameters of the models and their dynamic response.

The power factor and the maximum ramp rates modules are tested with all WTGs in service to verify that the requirements are met. Power factor tests consist in supplying and absorbing a maximum amount of reactive power at different levels of active power. Maximum ramp rate tests consist in performing a power plant shutdown sequence followed by a startup sequence. These tests are not really used to validate the models but are rather helpful to fix model parameters.

The last module regarding the power quality is not covered by scheduled testing but by means of a monitoring system that verifies harmonics and emission limits. The recordings are compared to the report provided by the developers to verify if the requirements are met. However, they are not useful to validate the EMTP model since the WPP is represented by a single-wound generator and does not simulate the detailed collector bus system and individual wind turbine generators.

Field tests department

Hydro-Québec field-testing department (UMES) conducts a wide range of special tests and measurements for Hydro-Québec and has done so for 30 years.

To test WPP, UMES installs a monitoring systems to record three-phase voltages and currents generally at three locations within the plant: at the point of interconnection, at the starting point of a 34.5 kV feeder of the collector system and at the terminals of a WTG connected to the same monitored feeder. For extended model validation, other signals within the wind turbine are monitored including the rotor side converter voltages and currents, the network side converter currents, and the DC bus voltage.

High speed recorders with anti-aliasing filters are used. Normally, the sampling rate is 5 kHz with at least a 200 second window per event. The monitoring system is reachable via an Ethernet connection for remote trigger and data retrieval. UMES has also the responsibility to perform the data processing and analysis of the recordings in order to verify the compliance with the interconnection requirements and to extract relevant data for model validation.

Hypersim

The Hydro-Québec Research Institute (IREQ)[29] also has an important expertise in control system and wind generation modeling for extensive studies of electrical networks. The simulation environment used is Hypersim, a real-time simulator and powerful simulation tool that uses a highly detailed representation of the Hydro-Québec network. A full-transient detailed model of a Type 3 WTG was developed at IREQ using the MATLAB® SimPower Systems Toolbox. The model was also implemented in EMTP and in the Hypersim real-time simulator.[30] This model is in the process of being validated with data processed by the UMES team. The range of events recorded does not make it possible to validate the model completely and the design and parameters will continue to be adjusted to improve the representation of the wind turbines. The validation of the MATLAB® model developed by IREQ was very useful to validate and improve Hydro-Québec's Siemens PTI PSS®E user model.[31]

4.2.2 GE Example – based on GE's work with client facilities

In the case of the first example presented here, a 10 MVar capacitor bank, located at the 25kV WPP collector bus, is switched off-line as an external physical stimulus. Figure 4.1 shows detailed response to capacitor switching from the WindCONTROL®. The WindCONTROL® system allows coordination of all on-line turbine-generators for plant-level fast and smooth voltage regulation at the point of interconnection (POI), located contractually at the 25kV substation bus. The red curve (Q_ACTUAL [KVar]) shows that total plant reactive power initially drops after the switching action, but the fast autonomous controls on each turbine generator quickly and stably respond to increase reactive power generated by individual turbines, shown by the orange curve (Q_TURBINES [KVar]). The WindCONTROL® command (Q_CMD) distributed to the turbines is shown in blue. The response of Q_CMD is dominated by the gains of the voltage regulator portion of the WindCONTROL®, specifically the proportional gain, K_{pv}, and integral gain, K_{iv}. The difference between the response of the individual turbines (Q_TURBINES [KVar]) and the WindCONTROL® command (Q_CMD) is due to the dynamics of the individual wind turbines. The coordinated response of the wind plant and the individual

[29] http://www.hydroquebec.com/technology/index.html

[30] R. Gagnon, G. Sybille, S.Bernard, D. Paré, S. Casoria and C. Larose, "Modeling and Real-Time Simulation of a Doubly-Fed Induction Generator Driven by a Wind Turbine," IPST Conf., Paper No. IPST05-162, Montréal, Canada, 2005.
C. Larose, R. Gagnon, G. Turmel, P. Giroux, J. Brochu, D. McNabb and D. Lefebvre, "Large Wind Farm Modeling Techniques for Power System Simulation Studies," in Proc. 8th International Workshop on Large-Scale Integration of Wind Power into Power Systems, Bremen, Germany, Oct. 14-15, 2009.

[31] C. Langlois, D. Lefebvre, L. Dube and R. Gagnon, "Developing a Type-III Wind Turbine Model for Stability Studies of the Hydro-Québec Network," in Proc. 8th International Workshop on Large-Scale Integration of Wind Power into Power Systems, Bremen, Germany, Oct. 14-15, 2009.

turbines is multi-modal: a fast initial response to address severe perturbations as well as a slower, grid friendly refinement. For purposes of this test, the automatic control of the capacitor bank by WindCONTROL® was disabled and manual switching was used as a stimulus to record individual WTG response.

The detailed plot in Figure 4.2 shows a zoomed view of the response to step change in voltage at the WTG. The very fast initial response will dominate and saturate the controls for big events. The wind plant will do everything as quickly as it can to mitigate a large disturbance. In this case, the fast response took approximately 200 milliseconds. The slow, refined control then takes over to allow for coordination with other equipment and maintain post-disturbance stability. This aggregate response also allows for a very abrupt action when needed, and a grid-friendly refinement that maintains stability in less severe cases.

The green curve in Figure 4.3 shows that when the capacitor is switched off-line, the measured voltage at the point of interconnection (or POI) decreases due to reduced reactive power flowing into the grid. The response of the individual WTGs is to rapidly increase reactive output to make up for the loss of reactive power supplied by the shunt capacitor. The plant level control then responds to this initial under-voltage condition and attempts to restore the POI voltage by increasing each wind generator's reactive output by equal amounts until the plant voltage settles to the control set point determined by the operator. The lower traces in Figure 4.3 show a gap during the period when the capacitor bank is online between total plant Q (Q_ACTUAL) and summation of Q out of each WTG (Q_TURBINES). This gap represents the capacitive reactance added by the shunt bank. When the capacitor is switched offline, the gap between Q_ACTUAL and Q_TURBINES closes and all reactive power is supplied solely from the WTGs. The initial loss in plant reactive power is mitigated within approximately 15 seconds as each WTG settles to a new, increased level operating point of reactive power. This new, increased reactive level for each WTG, is the total Q increase from all units on-line in the plant, divided by the total number of units online at the time of the test.

Figure 4.4 shows a comparison between these measured values and the simulation results of the PSLF model. Model outputs Q_g, Q_{plant}, Q_{cmd} and V_{reg} correspond to measured Q_TURBINES, Q_ACTUAL, Q_CMD and U_LINELINE respectively. This plot shows the model performance adequately represents what is happening in the field. The response matches closely, with a difference immediately following the switching operation being due to lower sampling rate in the measurement than in the GE PSLF® simulation.

Response to grid events demands relatively rapid control action. Manual grid or plant operator changes in operating set-points do not normally demand fast response, and indeed, system behavior ought not to be rapidly disturbed by moving set-points. Figure 4.5 shows the response of GE plant to 2% step in voltage reference. The blue trace in the figure shows a well mannered response to the reference step. The red trace is from the simulation model, which matches very

well. In the blue trace, after, the perturbation occurring about 8 seconds after the reference change the plant supervisory control switched on a shunt capacitor to retain dynamic range on the wind turbines. The switching perturbation is rapidly balanced by the turbines, allowing the response to continue smoothly.

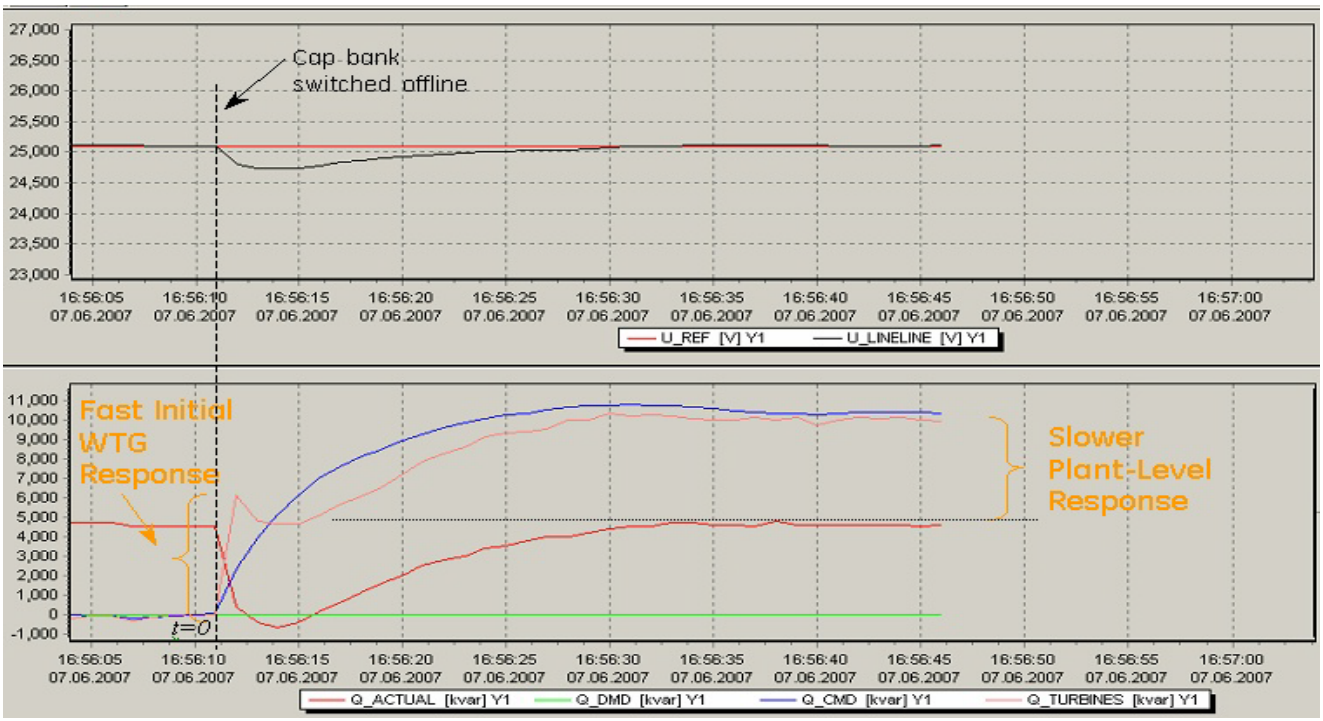


Figure 4.1: 10 MVar Capacitor removal response measured from WindCONTROL®.

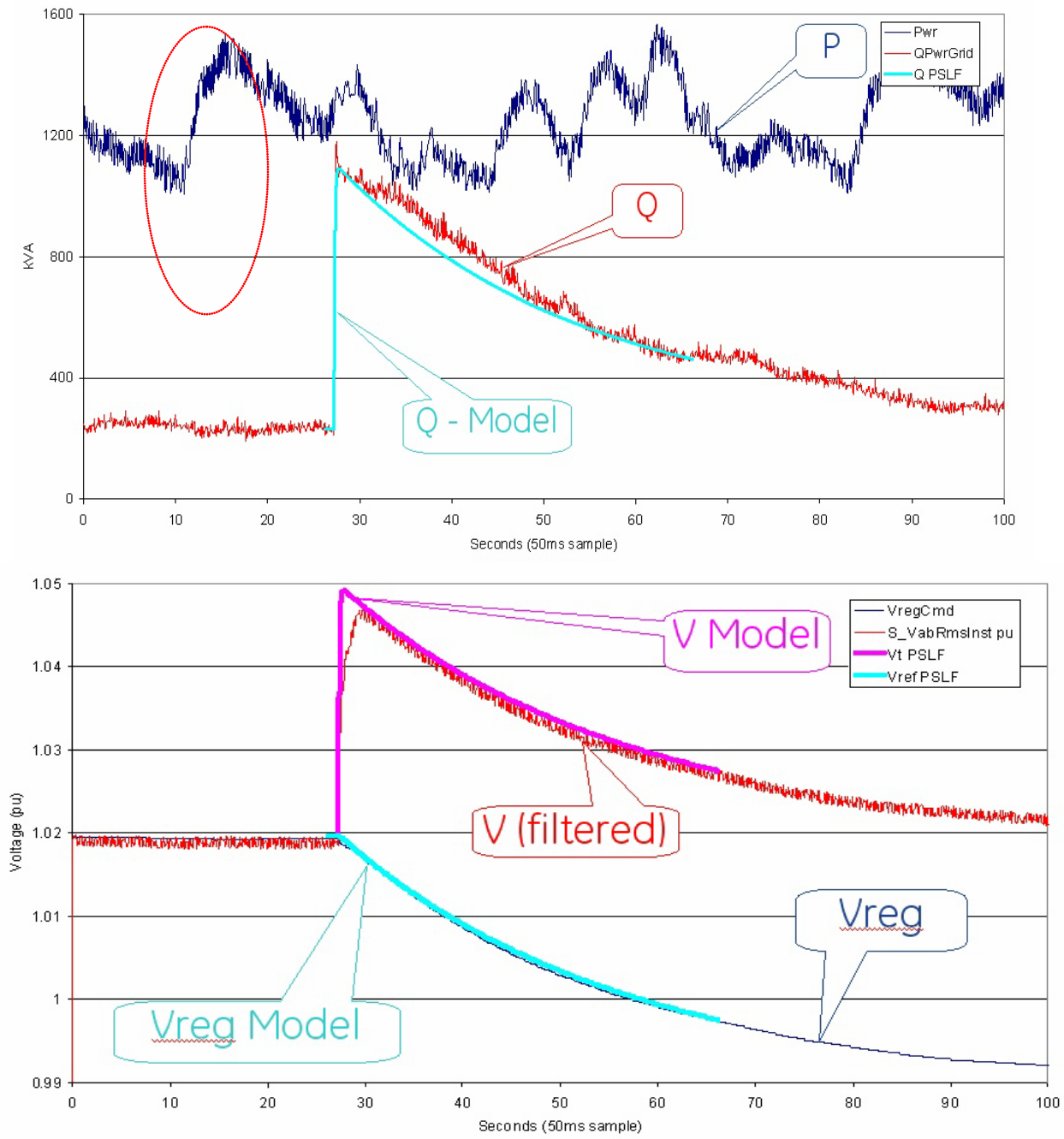


Figure 4.2: Wind turbine-generator level voltage step test response

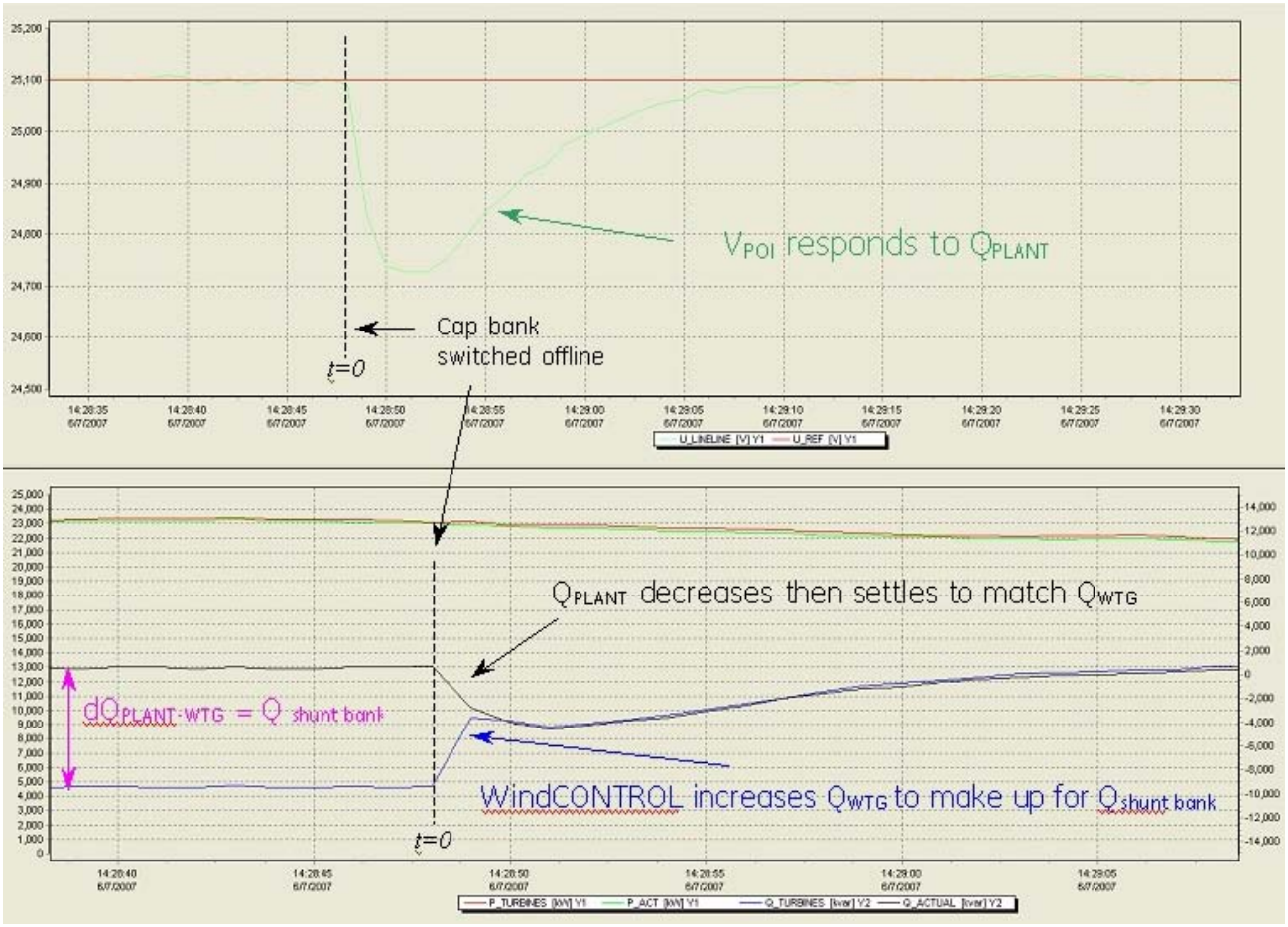


Figure 4.3: 10 MVar Capacitor removal response – POI variables.

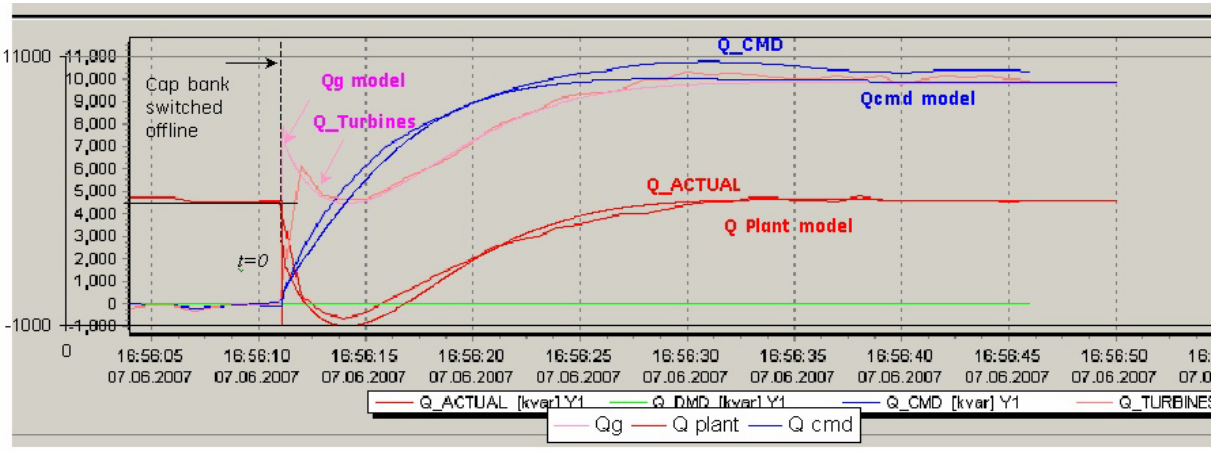


Figure 4.4: 10 MVar **capacitor removal field test vs. simulation results**

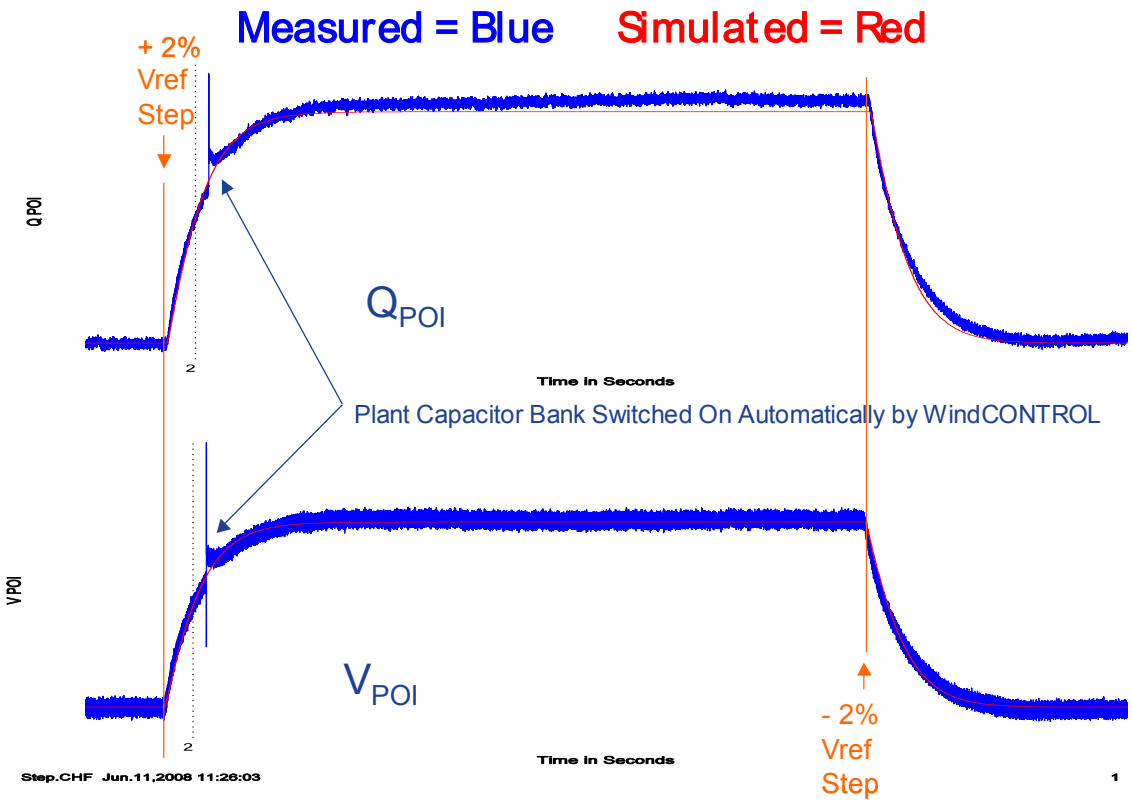


Figure 4.5: A different step test. +/- 2% step of voltage reference

The performance for grid fault events is of considerable interest in system planning. Staging faults, particularly severe ones on operating wind plants, is difficult and expensive. Figure 4.6 shows a comparison between a staged fault test and the (present) Siemens PTI PSS®E model of the GE 2.5 (full converter) WTG. The fault event is quite severe: a 3-phase 700ms of voltage depression to less than 20% of nominal at the high voltage terminal of the WTG unit transformer. The measurement traces (on the left) include some of the signal noise characteristic of measurement and extraction of fundamental frequency positive sequence information from real, high resolution measurements. The simulation traces on the right, are, of course, cleaner. The match between test and simulation is of very high fidelity for phenomena relevant and legitimately examined with positive sequence simulation tools (i.e., greater than one cycle).

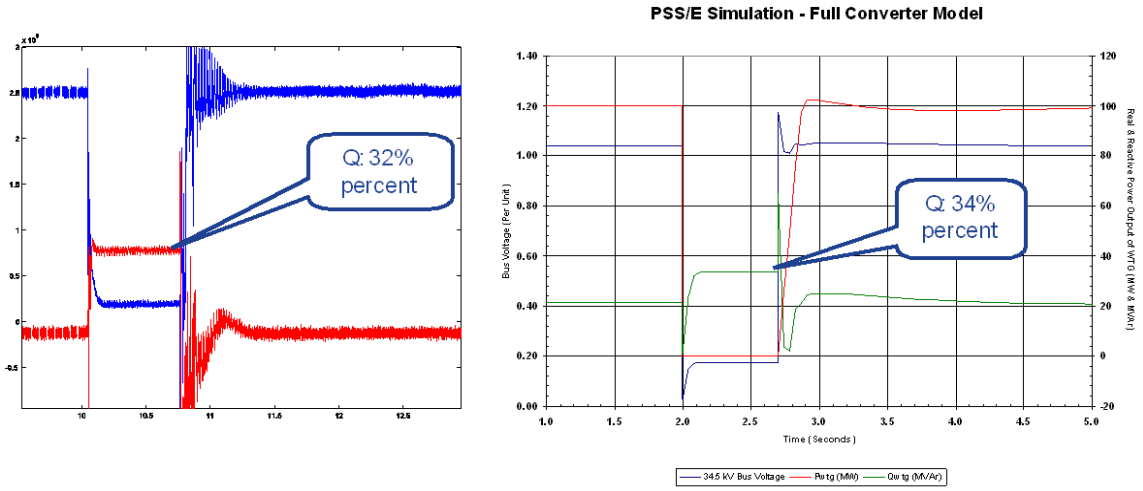


Figure 4.6: GE 2.5 WTG Fault Test vs. PSS/e Model Performance

The discussion provide above is solely geared to hardware testing and validation, however, another highly valuable and legitimate means of providing validation of simulation models (for planning and otherwise) is to use more complex simulation software to validate simpler planning models. Manufacturers normally have highly complex, and highly proprietary, models of their equipment. These models are used, among other things, to design equipment and are normally physically based and must have sufficient fidelity for original equipment manufacturers (OEMs) to make sound engineering judgments for equipment design and application. The OEMs are highly motivated to have these detailed high fidelity equipment level models. These detailed models therefore can often be used to design, test and validate simpler planning models to be used by the industry.

There is a long, accepted history in the power industry of this practice. For example, a typical (GE) gas turbine has on the order of 4,000 state variables in the design model; planning models typically have on the order of four state variables: simplification is necessary and expected. These design codes have been used to develop planning models of gas turbines. Figure 4.7 below shows a comparison between a fault simulation using a GE design code (GE WindTrap®) and the planning model in GE PSLF® for a GE 1.5 (double fed machine) WTG.

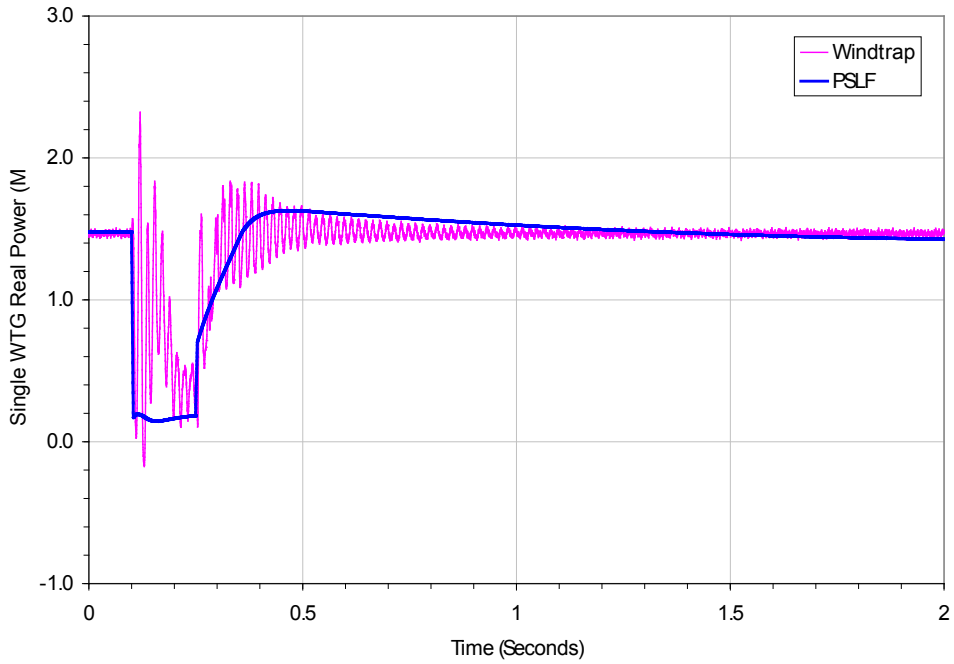


Figure 4.7: Detailed Design Simulation (GE WindTRAP®) vs. GE PSLF® Model Performance (active power during a severe fault for a GE 1.5 WTG)

5. Summary & Recommended Actions – Standards Implications

This document has presented a general overview of modeling and model validation as it pertains to variable generation resources. Clearly, to date, the bulk of the experience and work has been on wind turbine generators. Never-the-less, similar approaches for modeling and model validation are being pursued for other variable generator technologies such as PV.

Non-proprietary and publicly available models for the simulation of steady-state (power flow), short-circuit (fault calculations) and dynamic (time-domain simulations) behavior of such generation resources must be made readily available for use by power system planners. Furthermore, these models should be routinely validated to ensure proper representation of variable generation power plants in bulk power system studies. A model is valid if its dynamic behavior is close enough to reality so that its influence on the network of interest (i.e. used for power system studies) is consistent with the fidelity of model structures and available data for the power system and other generation, as it pertains to the phenomena of interest (i.e. in stability studies). That is, perfect curve fitting is not necessary, but to the extent possible erroneous model dynamics must not result in a notable over-design or under-design of the network.

Each of the NERC standards discussed below in Section 5.2 address to aspects of meeting a standard: (i) the technical requirement, i.e. the need to define, measure validate a model, its parameters etc., and (ii) the procedural requirements, i.e. the functional model of how this technical requirement should be met, reported and monitored. The bulk of this working group's recommendations stated below address the technical requirements. Variable generation is a new and quickly evolving technology and consideration should be given to the timing with which standards be implemented.

Section 5.1 below first gives a summary of the planning process based on NERC standards to put the discussions in this report into context with the NERC standards. Then in Section 5.2 we provided our recommendations and comments on the NERC existing and developing standards.

5.1. Applying the NERC Standards

The NERC standard FAC-001 (see Figure 5.1) should be expanded to clearly cover modeling requirements during the coordinated joint study phase of the Facility connection process. Simple generic models of variable generation may be adequate for the IES phase and more detailed models may be needed for the IFS phase. Validation of the simple and detailed model parameters may be needed during commissioning.

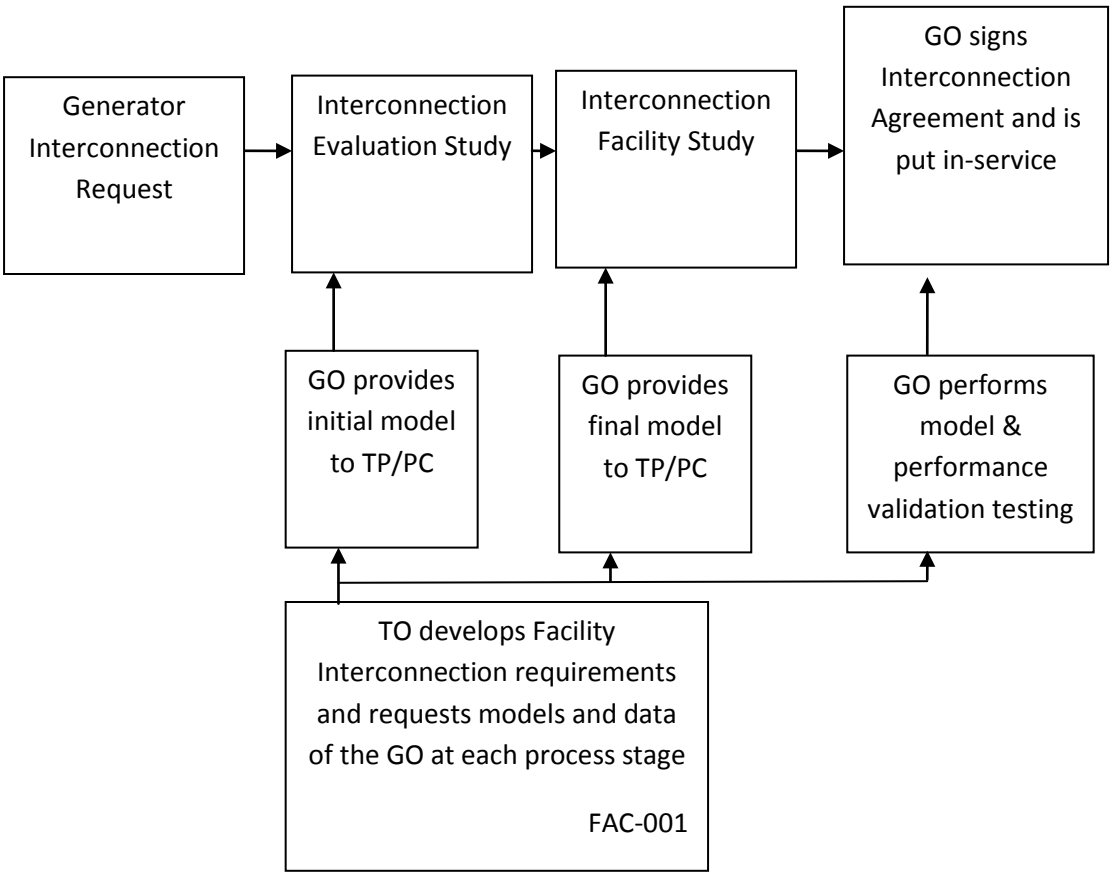


Figure 5.1: Facility connection process.

The generic model with associated parameters feed into the NERC model building process shown in Figure 5.2. As an example, for WTG, presently there is insufficient evidence of the accuracy of presently available generic models for WTG[32] for all the various WTG manufacturers. Some confirmation tests during commissioning or type tests or comparison simulation tests with a detailed model are necessary to get buy in from the Transmission Owner/Planner. As the technology matures, and generic models are enhanced, and associated data parameter sets are developed for specific machine types, the new generic models will become more accepted as is the case with models of hydro or thermal plants.

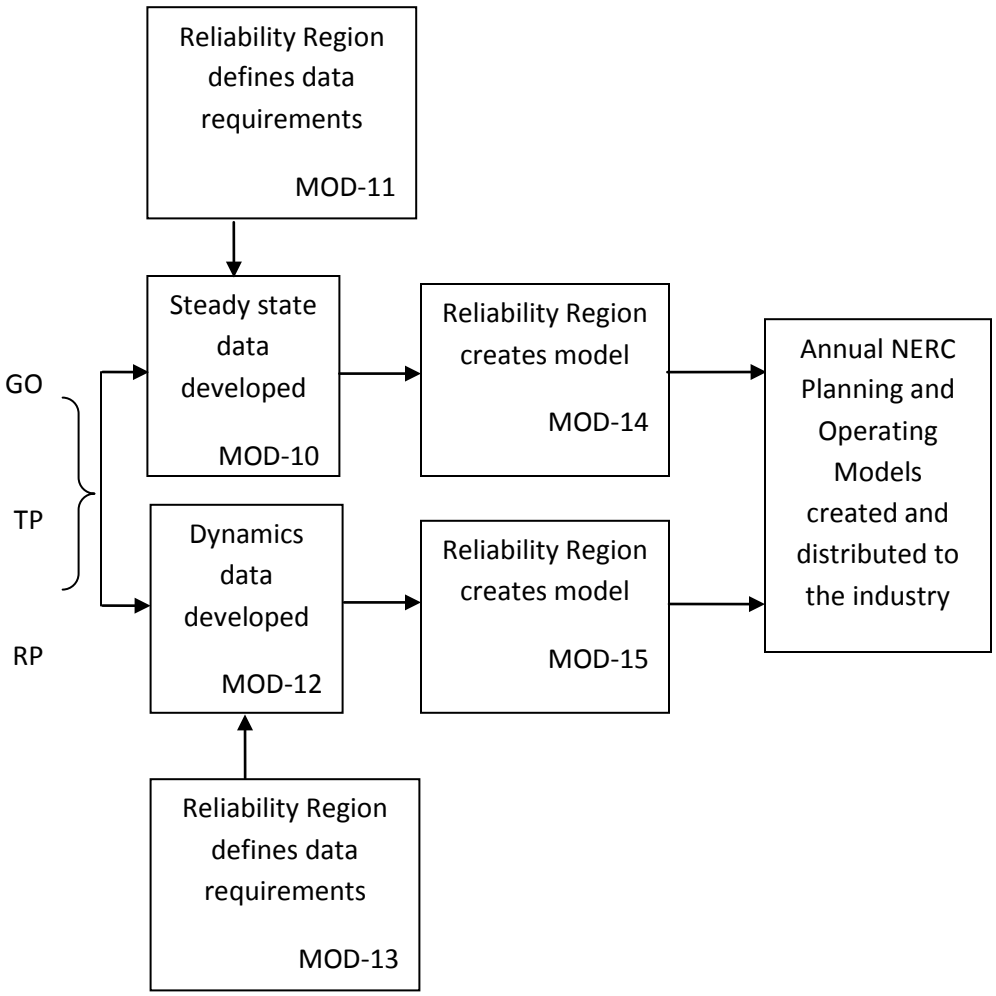


Figure 5.2: Annual NERC Model Development Process

[32] PSS®E-32.0 Program Application Guide: Volume II, Chapter 21.
PSS®E-32.0 Model Library, Chapters 17 through 21
GE PSLF User's Manual. v.17.0_04. October, 2009.

The regional model building manuals developed as part of MOD-11 and MOD-13 must provide sufficient clarity to model variable generation. These manuals may ask for best available models or generic models. These models cover the operational time frame and the 10-year planning horizon. The manuals do not currently cover the frequency for revalidating model data.

While not included in the standards, more emphasis is currently being placed on meeting the Eastern Interconnection Reliability Assessment Group (ERAG) model building manual requirements in addition to regional requirements.

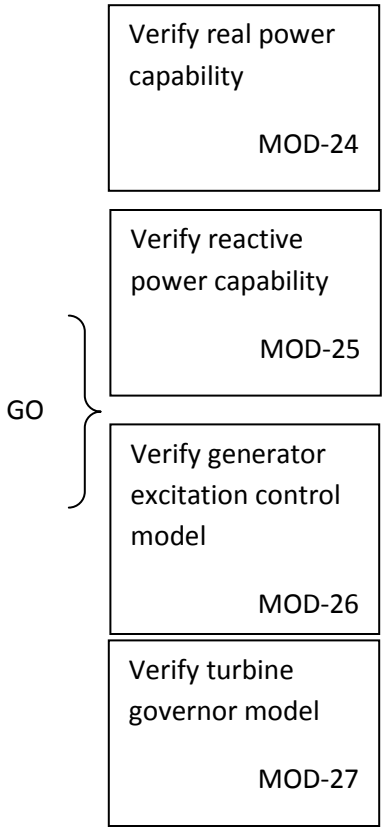


Figure 5.3: NERC Model Validation Process

The Regional Entities develop the test procedures and dictate testing frequency for the Generator Owners to follow. The model data then feeds in to the annual NERC model building process.

5.2. NERC Standards Technical Issues

One general comment is that the NERC Glossary of Terms would benefit from the term "Variable Generation" being include in it and appropriately defined. A suitable definition can be found in the Phase I report of the IVGTF.

MOD-011: Regional Steady-State Data Requirements and Reporting Procedures

The technical requirement in this MOD reads:

> "R.1.2 Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status."

This statement could be read to equally apply to variable generation as a source of generation. However, it may be prudent to explicitly include variable generation in this statement. For example, to change the sentence to:

> "R.1.2 Generating Units (including synchronous condensers, pumped storage, ***variable generation resources*** etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status. ***For variable generation a suitable aggregate steady-state model of the collector system and equivalent unit representing the full plant.***"

MOD-012: Dynamics Data for Transmission System Modeling and Simulation

This MOD equally applies to variable generation and needs no augmentation. The requirements in the MOD are quite generic. The requirements of this standard are dependent on and point to MOD 13, discussed below.

MOD-013-1: RRO Dynamics Data Requirements and Reporting Procedures

This MOD explicitly discusses synchronous type generation. It would be beneficial to include an explicit statement to cover variable generation. For example,

> "Plant-specific dynamics data shall be reported for variable generating units (e.g. wind turbine generators, PV etc.) such as the type of generating unit, its interface with the grid and the appropriate model and model parameters to adequately represent unit dynamic response for bulk power system studies. The typical size of a single variable generating unit (e.g. wind turbine generators, PV array, etc.) is several hundreds of kilo-watts to several mega-watts. Thus, it may be acceptable for the total plant to be represented by an adequate aggregated model of the collector system and a single equivalent generating unit scaled up to represent the total name-plate capacity for each type of generating technology employed in the plant. Furthermore, models may need to be provided for other equipment installed in the collector system or at the point of interconnection such as reactive compensation devices."

MOD-024-2 — Verification and Data Reporting of Generator Real Power Capability

This latest posting of this MOD, posted for commenting on January 18th, 2010, exempts variable generation from this requirement. It states:

> "Variable energy units such as wind generators, solar, and run of river hydro are exempt from the requirements of this Standard."

For a variable generation plant the definition of Real Power Capability can be slightly challenging. One way to view it is to see the total gross capability as the sum of the nameplate rating of all individual units within the plant, e.g. for a wind power plant the total sum of the nameplate rating of all wind turbine generators in the plant. However, there must be two realizations (i) the amount of actual power injected into the grid at the point of interconnection requires a suitable representation of losses on the collector system and auxiliary loads, and (ii) by its very nature variable generation is a highly variable energy source and thus it is quite rare to find point in time when all units in the plant are coincidentally at their peak nameplate capacity. Finally, the seasonal variable generation output variations need some discussion since they are quite different than conventional generation technologies.

MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability

The technical requirement in this MOD reads:

> "R1.5. Information to be reported:
>
> R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.
>
> R1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.
>
> R1.5.3. Verified Reactive Power of auxiliary loads.
>
> R1.5.4. Method of verification, including date and conditions."

Note: the above requirements are from the existing version of the standard. MOD-025 is currently being enhanced.

Although all of the above could equally apply to variable generation, some clarification may be needed. Namely, variable generation reactive capability of the "power plant" is not entirely inherent in the individual generating units. A variable generation power plant, such as a wind power plant, may contain many reactive power sources such as the individual generating units themselves (e.g. Type 3 or 4 WTG, see Appendix I), discretely switched shunt reactive devices

(e.g. shunt capacitors or reactors), smoothly controlled shunt reactive devices (e.g. SVC or STATCOM), or a combination of these devices. Thus, care should be taken as to how the total reactive capability of the power plant is defined and at what point (e.g. point of interconnection, and whether this is defined as the high or low side of the substation transformer). Also, it may not be practical under normal operating conditions to exercise the full reactive capability of the power plant (this is a known issue, even with conventional synchronous generator plants) to test it, thus it should suffice to demonstrate the plants reactive capability to the extent possible in the field and to then augment this with engineering calculations to derive the plants full reactive capability. This is particularly, true of variable generation because there is no control over the energy resource. So for example, a typical wind power plant may only achieve its name-plate rating for a hour or two during an entire year. Thus, it would not be possible to demonstrate the full reactive capability of the plant in the field. Rather, it should suffice to demonstrate the reactive capability of a single WTG and then to derive through engineering calculations (considering all other reactive devices in the plant, such as SVC, STATCOM etc.) the total reactive capability of the plant. These comments should be somehow used to appropriately modify MOD 25.

MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions – SECOND POSTING (and MOD 27)

MOD 26 (and MOD 27 *Verification of Models and Data for Turbine/Governor and Load Control*) are presently under development[33]. These two standards deal specifically with the routine validation of generating unit dynamic models for power system stability studies.

Presently, these standards are tailored explicitly to deal with synchronous type generators, since much of the language revolves around technology associated with synchronous generation (e.g. excitation system, AVR, power system stabilizers etc.). Thus, the following key items need to be clarified in these standards, as they pertain to variable generation. In addition, the comments that follow apply to all components in a variable generation plant that may include devices such as the actual power generating units, shunt compensation devices, centralized control systems spanning the entire facility, etc.:

1. Unit/Plant Size for Validation: These MOD's specify the size of generating unit above which model validation is required. It should be recognized that the typical size of a

[33] MOD 26 and MOD 27 standards under development are found at http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

variable generation unit is in the hundreds of kilo-watts to several megawatts range. Thus, the language should be changed (or introduced) to indicate "net power plant" size.

2. Validation of various technologies in a single plant: Variable generation power plants can consist of multiple generation technologies. For example, a wind power plant may consist of WTGs of two different types. Thus, we need to consider the following points as they pertain to variable generation:

    a. For a uniform variable generation plant (i.e. all generating units are of the same technology type) a single aggregate generator model representation should be sufficient.

    b. For a significantly diverse variable generation plant, the plant should be represented by multiple aggregated unit models representing each technology type.

    c. Unique representation of a group of variable generation units as a single aggregated generator model representation should be based on:

        i. The size of the group is a significant proportion of the total plant size (e.g. > 20% of plant rating).

        ii. Each group should represent a unique characteristic (e.g. Type 1 WTG as compared to a Type 3 WTG).

3. Validation of different control layers: Variable generation plants, such as wind power plant, may have several functional layers of control. For example, in a wind power plant with Type 3 WTGs we may have one level of closed loop voltage regulation at the terminals of the WTG, a second slower control loop that regulates voltage at the point of interconnection (POI), and a third layer of control that coordinates the switching of shunt capacitors at the POI based on the reactive output of the individual WTGs. In addition, devices such as STATCOMs may be present at the POI. Modeling and model validation should incorporate such devices/control layers to the extent that the dynamics of these functional layers are important for stability studies (see Figure 3.1).

4. Modeling and Model Validation: Models are an emulation of actual equipment. Not all model parameters necessarily translate to actual physical components or measureable features. Judgment needs to be exercised in the modeling and validation process.

    a. Models should be validated typically against the performance of an actual plant for a given event/disturbance, within the given operating range it is designed for.

b. Models should state clearly the type and the range of events they have been designed to simulated and the limitation of the models beyond which the model deviates from the actual variable generation plant performance (e.g. a model developed to represent electrical transient behavior of a WTG may not be adequate for studying wind fluctuations over a many minute time frame).

c. In general, the best approach to model validation is to use field (or test bench) measurements of various disturbances that must exercise the different control functions to a wide range of operation points. For example, a model is not necessarily valid if the only a comparison between simulation results and field measurements for a single voltage step response is performed at one operating condition. Ideally, illustration of validation against recorded response to various system disturbances (faults, frequency deviations, etc.) gives the greatest confidence in validation.

d. A model is valid if its dynamic behavior is close enough to reality so that its influence on the network of interest (i.e. used for power system studies) results in relatively negligible errors for the phenomena of interest (i.e. in stability studies). That is, perfect curve fitting is not necessary, but to the extent possible erroneous model dynamics must not result in a notable over-design or under-design of the network.

5. Future functionality: Due to the rapidly evolving nature of variable generation technologies, variable generation models should be of a modular nature, such that future functionality can be incorporated, as much as possible, into old model structures by adding a functional modular block. For example, presently Type 3 and 4 WTGs do not exhibit inertial response. However, at least one manufacturer now supplies a functional control addition that can emulate inertial response on these units. Such functionality is likely to be made available soon by most vendors. Thus, a functional model block can be developed that can be added to the existing models for Type 3 and 4 WTGs to emulate the behavior of this additional control.

6. Modeling of protection: Variable generation, much like conventional generation, will have associated under/over voltage and under-over frequency protection. These should be modeled. Attention should also be given to protective relay coordination with plant controls, particularly in light of the nature of the grounding system within the variable generation plant (e.g. a wind power plant spans an entire collector system, which can be grounded in several different ways and thus have various implications on protective relay coordination). Such coordination issues relate to the PRC and FAC-001 standards.

7. Issues related to the fuel source for variable generation: For variable generation one needs to be cognizant of the variable nature of the energy source and thus the possible impracticality of performing model validation at a desired plant output, but rather having to accept model validation at whatever plant output can be achieved at the time of testing or disturbance monitoring.

8. Revalidation: How often should models be revalidated?

    a. Many variable generation technologies are rapidly changing, for example in wind power plants new control software or new setting may be uploaded every year, if not sooner.

    b. If the changes are insignificant, the existing dynamic models should be revalidated if possible as a matter of prudency – say within six months or so of a control system update/upgrade. The changes (in parameters or dynamic model) should be reported to the local Reliability Entities.

    c. If the changes are significant, the existing dynamic models should be revalidated – say within three months or so after the update/upgrade. The changes (which may include a new module, new software etc.) should be reported to the local Regional Entities.

5.3. Final Recommendation

An earlier draft of this report and recommendations were presented to NERC's Planning Committee at their March, 2010 meeting. The Committee members urged the IVGTF to pursue NERC reliability standard development. Thus, several NERC Standards Drafting Teams undertaking MOD Standard development will be contacted to present the recommendations from this report for their consideration and incorporation in subsequent updates. The standard drafting teams for MOD-026 and MOD-027 are aiming to incorporate variable generation considerations in the next release of these draft standards.

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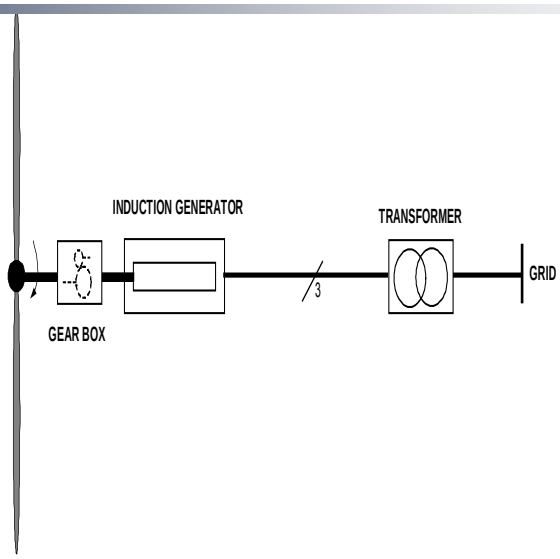
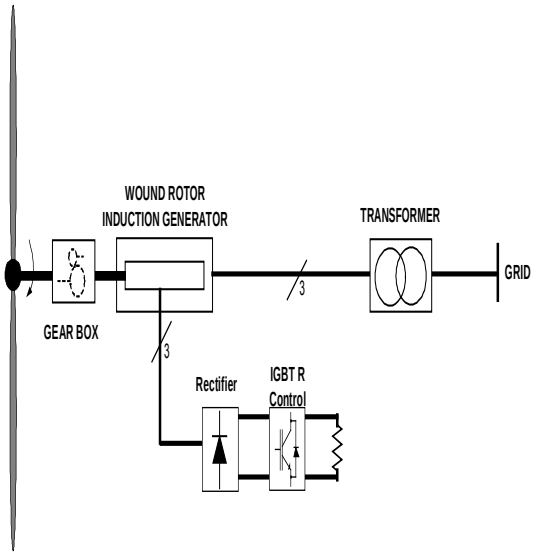
Appendix I: Wind-Turbine Generation (WTG) Technologies

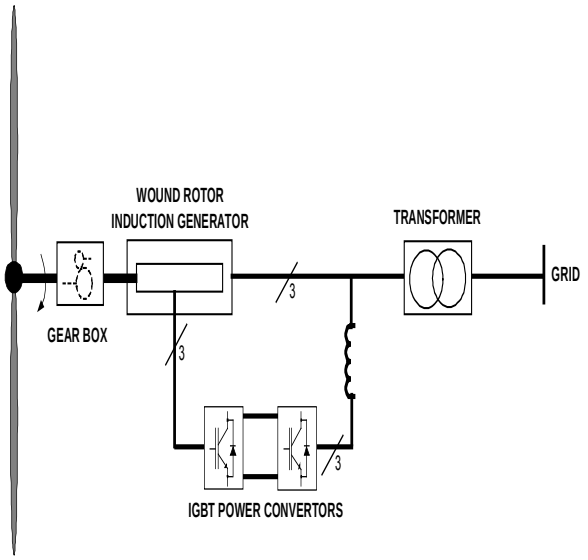


(a) Type 1 Wind Turbine-Generator: Fixed Speed Induction Generator

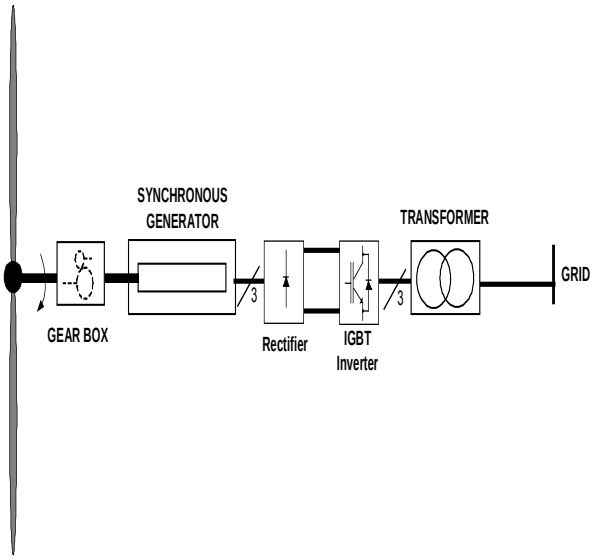


(b) Type 2 Wind Turbine-Generator: Variable Slip Induction Generator [34]

[34] IGBT R control = Resistor controlled by Insulated Gate Bi-Polar Transistor



(c) Type 3 Wind Turbine-Generator: Double-Fed Asynchronous Generator



(d) Type 4 Wind Turbine-Generator: Full Power Conversion

Acronyms

CSP – Concentrating Solar Power

CIGRE - International Council on Large Electric Systems

DFAG – Doubly Fed Asynchronous Generator (also often referred to as DFIG – Doubly Fed Induction Generator)

FERC – Federal Energy Regulatory Commission

HVDC – High-Voltage Direct-Current transmission

IEC – International Electrotechnical Commission

IEEE – Institute of Electrical and Electronic Engineers

IGBT – Insulated-Gate Bipolar Transistor

IGCT – Insulated-Gate Commutated Thyristor

IVGTF – Integration of Variable Generation Task Force

ISO – Independent System Operator

LCC – Line-Commutated Converter

LVRT – Low-Voltage Ride-Through

MOD – Modeling, Data and Analysis Standards

NERC – North American Electric Reliability Corporation

OEM – Original Equipment Manufacturer

PHEV – Plug-in Hybrid Electric Vehicle

PV – Photovoltaic

POI – Point of Interconnection

RPS – Renewable Portfolio Standard

RTO – Regional Transmission Operator

SAR – Standards Authorization Request (NERC process)

SCADA - Supervisory Control and Data Acquisition

SSTI – Subsynchronous Torsional Interaction

STATCOM – Static Compensator (voltage source converter based technology)

SVC – Static Var Compensator (thyristor based technology)

TSO – Transmission System Operator

VAr – volt-ampere reactive (standard units for reactive power)

VRT – Voltage Ride-Through

VSC – Voltage Source Converter

WPP – Wind Power Plant

WTG – Wind Turbine Generator

WECC – Western Electricity Coordinating Council

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard PRC-012-2 Remedial Action Schemes

Frequently Asked Questions

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)

July 2015

RELIABILITY | ACCOUNTABILITY

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Q&A 6

Attachment A – Standard Drafting Team Members 17

Introduction

The Project 2010-05.2 – Special Protection Systems Standard Drafting Team (SDT) developed this background and Frequently Asked Questions (FAQ) document to explain the key concepts incorporated into the revised definition, as well as the team's approach and intent. This document will remain available as part of the official project record for the Remedial Action Scheme (RAS) definition. The drafting team has updated this (FAQ) document to reflect all revisions made to the RAS definition based on stakeholder feedback.

Contact the NERC Standards Developer, Al McMeekin, at 404-446-9675 or at al.mcmeekin@nerc.net with any comments or questions.

Background Information Regarding the Definition of RAS

Section 1. Design and Maintenance Requirements

Section 2. Study and Documentation Requirements

Section 3. Operational Requirements

Section 4. Analysis of RAS Operations

Why was the Reliability Coordinator chosen to perform RAS reviews? [Gene]

The FERC directive (753? Re: PRC-012, PRC-013, PRC-014) that rejected the Regions as acceptable entities for responsibility under NERC Functional Model and standards identified that the proper entity(ies) must have Planning or Operating responsibilities within the NERC Functional Model. The NERC white paper suggested either the PC or RC for the review responsibility. The Regions have as many as 30 PCs for one RC, though other Regions have a single PC and RC for the Region. Overall, there are 15 RCs and about 80 PCs. Since this standard needs to apply across North America, the Reliability Coordinators clearly have the widest possible view of the System of any Operating or Planning entity.

The RCs have corporate independence from RAS owners, while PCs in some Regions often are effectively subsidiaries of a RAS owner. Such PCs could not effectively perform an independent review of any RAS proposed by their owner.

The SDT considers the RC as the FM entity most likely to represent the reliability interests of independence, wide geographic oversight, and continuity characteristic of the present RRO administered reviews. The SDT considers the RC as unlikely to be a stakeholder in any given RAS and thus is a sufficiently independent FM entity to conduct the reviews. In many instances the RC geographic oversight exceeds that of the respective PCs. The larger RC geographic oversight will minimize fragmentation of the present RRO administered reviews.

With regard to the need for multi-disciplinary expertise, the RC may designate another entity to conduct the review per the checklist in Attachment 2 if the RC does not believe it has the necessary qualifications itself. The present assignment to the RROs may continue under this standard should the RRO agree to continue the review function at the request of the RC(s). Continuity may be assured by institutionalization of the review panel within a RC or RRO area.

Why are Planning Coordinators not required to perform annual evaluations of RAS performance? (Gene)

TOP-005-1_R3 requires BAs and TOs to perform operational reliability assessments (e.g. RTCA, day ahead, seasonal), which includes data describing new or degraded special protection systems [RAS]. In addition, IRO-005-1_R12 requires that RCs must share any pertinent data, such as SPS [RAS] with potentially affected BAs and TOs. Short- to medium-term operating assessments that include RAS are already required by other standards, so an additional requirement duplicating that effort is not necessary.

TPL-001-4_R2 also requires the TP and PC to perform annual Planning Assessments of the Near-Term Transmission Planning Horizon. R2.7.1 acknowledges that new, modified, or removed SPS [RAS] may be part of a CAP used to fulfill Table 1 performance requirements. Planning horizon annual assessments are already required by the TPL-001-4 standard, including RAS, so an additional requirement duplicating that effort is not necessary.

Why is the 5-year evaluation/assessment assigned to the Transmission Planner, rather than the Reliability Coordinator? [Bobby]

Why were the Regional Entities not included as part of the review process? (Gene)

FERC directive (753? Re: PRC-012, PRC-013, PRC-014) rejected the Regions as acceptable entities for responsibility under NERC Functional Model and standards. FERC indicated that proper entity(ies) must have Planning or Operating responsibilities within the NERC Functional Model. Regions are not Planning, Operating or Owning Entities in the NERC Functional Model, so cannot have responsibilities assigned to them by the standards.

Why do RAS need to be reviewed by a group other than the RAS owner? (Rob)

RAS are unique and customized assemblages of various protection and control components that do not conform to any standardized or otherwise typical or customary utility practices. As such, they have a potential to introduce serious reliability risks if not carefully planned, designed, and installed. While a RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, it might also introduce other reliability risks that may not be apparent to a RAS entity focused on the issue or advantage at hand. Any such unforeseen risks need to be identified, and a review by a multi-disciplinary panel of SMEs is the best means to identify such RAS introduced risks and recommend RAS modifications where necessary.

Why is RAS approval required as part of the outside review? (Amos)

RAS approval is required as part of the outside review because it is the measure for which evidence of a review occurred. An approval shows that the RAS (new, modified, or retired) has met the minimum requirements of Attachment 1. As part of the process to get approval, the RAS has been coordinated with other entities through the review process and approval of which is indicative that all issues have been resolved including coordination issues.

Why was a continent-wide review entity not prescribed? (Gene)

Reviews limited to specific areas are difficult enough to identify an appropriate reviewing entity. No appropriately skilled continent-wide body presently exists. Some familiarity by the reviewers with the area electric system pertinent to each RAS is very useful to promote an effective and efficient RAS review process, which would be much more difficult for a single continent-wide reviewing entity.

What is meant by "single component failure" and why is it required to mitigate this for Planning Significant and Planning Limited schemes? (Al E. and Gene)

If a RAS is deemed necessary to satisfy the performance requirements of a NERC reliability standard such as, and in particular, TPL-001, it is necessary that its operation under the conditions and events for which it is designed to

operate be assured in the operational realm as well as in the planning realm. Full redundancy of the RAS components achieves this goal. Full redundancy is also consistent with the performance requirements of TPL-001, Table 1, Category P5 where a component (relay) failure of a protection system is combined with a normal planning contingency. The companion consideration associated with the PS redundancy requirement is the assurance of avoiding significant adverse system impacts.

The level of redundancy of a RAS can vary depending on the design characteristics of the scheme, the actions it performs and the conditions it is intended to mitigate. The minimum redundancy level required in Attachment 1 is that "a single component failure in a Planning Significant (PS) or Planning Limited (PL) RAS does not prevent the BES from meeting the same performance requirements as those required for the System events and conditions for which the RAS was designed". The intent of this requirement is to minimize the risk of a RAS not being able to operate as intended if a single component fails to operate. The SDT contends that failure of a single component critical to the correct operation of a RAS has a relatively high occurrence and considers that the level of redundancy of any RAS classified as PS or PL should be such as to minimize this risk. This minimum redundancy level can be achieved by different means, as long as the RAS is designed such that it is capable of performing its intended function while itself experiencing failure of a single component. The most obvious way to obtain sufficient redundancy is to duplicate the components that are crucial to the correct operation of the RAS. For schemes performing action involving like load shedding and generation rejection, over arming can also be an option (i.e. providing more corrective action than necessary to ensure sufficient action in case of single component failure).

What is required for RAS inadvertent operation? (Rob)

What is meant by RAS coordination with other RAS and Protection Systems? (Gene)

RAS are complex schemes that typically take action which trips load or generation or re-configures the system. Many RAS depend on sensing specific system configurations to determine whether they need to arm or take actions. Overlapping actions among RAS would have the potential to result in cascading, unless coordinated. Similarly, RAS reconfiguration of the system changes available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination. A third coordination example is a RAS that detects a line outage as a trigger to action, but delays executing that action until automatic reclosing on the faulted line is attempted and fails. The delay time for the action must be longer than the reclosing open interval on the line. Many RAS are intended to mitigate thermal equipment overloads following outages of other equipment. Typical intended action is shedding of load or generation, or system re-configuration. A small coordinating delay, e.g. up to a few seconds, is required to avoid initiating action while a system fault is present, However a delay of several minutes may be acceptable as long as that is compatible with the thermal characteristics of the overloaded equipment. This may allow operator intervention.

Why do RAS not need to be classified? (Al E.)

Classification of a RAS is necessary to provide a consistent, continent wide framework for reliability risk categorization. The classification categories consider RAS inadvertent operation, and RAS non-operation. The resultant classification will determine the level of requirements proportionate to the reliability risk, the level of Reliability Coordinator review, and the RAS design criteria (redundancy).

Why was "RAS misoperation" not defined? (Gene)

The SDT recognizes that the suggested description of "RAS Misoperation" in the NERC white paper would be a plausible starting basis if a separate definition is needed. However, the SDT contends that the description of incorrect operations in the proposed Requirement R6 and its Rationale, provide a satisfactory alternative to a formal NERC Glossary definition.

What constitutes functional modification of a RAS? (Davis – maybe include examples of what is and what isn't)

Any modification to RAS hardware beyond the substitution of components that merely preserve the original functionality is a functional change. Any change in RAS logic, RAS relay settings, RAS control settings, or any other modification that affects overall RAS functionality, timing, or redundancy level as documented in the original submission for review are functional changes. RAS modifications identified by a Corrective Action Plan developed pursuant to R5 or R7 beyond the substitution of components that merely preserve the original functionality is a functional change.

Some examples of functional changes include:

- Changes to inputs, outputs, or internal scheme logic
- Major component changes
- Revision of the existing RAS architecture
- CAP modifications resulting from R5 evaluations or R6 incorrect operation reviews

RAS removal is the extreme form of RAS functional modification. Any RAS proposed for removal needs to be evaluated under the "Transmission Planning Evaluation" section of the Attachment 1 checklist. The focus of the reviews for RAS removals should be on the system performance after scheme removal to show that the contingencies that the RAS was designed to mitigate no longer result in the system performance issues that the scheme was intended to mitigate. However, reviews of the sections on the Implementation Design and Operational Data are not really relevant for RAS removals, so are not necessary.

How is the RAS-entity identified, what are the RAS-entity's responsibilities, and what are the responsibilities of other owners of RAS components or Facilities who are not the RAS-entity? (Gene)

How is the RAS-entity identified, what are the RAS-entity's responsibilities, and what are the responsibilities of other owners of RAS components or Facilities who are not the RAS-entity?

The RAS-entity is a NERC functional model entity that owns all or a significant part of the RAS components or other Facilities controlled by the RAS. The RAS-entity will include one of the following:

- Transmission Owner
- Generator Owner
- Distribution Provider

When all RAS components and Facilities controlled by the RAS have a single owner, the RAS-entity is that owner. When the components that make up a RAS and/or RAS-controlled Facilities have more than one owner, the multiple owners may designate a single entity as the RAS-entity. Most often the owner of the RAS controller (when there is one) will be the RAS-entity. However, the various owners may designate some other entity with an ownership interest in the RAS as the RAS-entity.

The RAS-entity has the responsibility to prepare the material identified in Attachment 1 for presentation to the RC, which is the request to approve a new or modified RAS. The RAS-entity will be the primary information conduit for other owners of RAS components and RAS-controlled Facilities during the RAS review process, though other owners may also participate in the RAS review process.

Generator Operators or Transmission Operators of Facilities or components of a RAS have the responsibility to keep all other Operators with a reliability need regarding a RAS informed of any functional modifications made to their individual Facilities or RAS components. This is a form of coordination per PRC-001_R2. While Transmission Owners and Generator Owners do not have direct responsibility under PRC-001, they do have the business interest (and incentive) to approve and finance any appropriate RAS modifications to keep their RAS in compliance with applicable reliability standards.

What is meant by "single RAS component failure" and "redundancy" in this standard? (Gene and Al E.)

The philosophy of the phrase regarding System performance while a RAS experiences a "single component failure" from PRC-012-0 is carried over in to this standard. This phrase is often shortened to "redundancy," but in the context of this discussion, these terms are used interchangeably.

> PRC-012-0 R1.3
> Requirements to demonstrate that the SPS [RAS] shall be designed so that a single SPS [RAS] component failure, when the SPS [RAS] was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirement defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

The critical part of PRC-012 R1.3 is that a RAS "shall be designed so that a "single [RAS] component failure. . . does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards. . . ." This language certainly covers RAS measuring devices, controls, communications and devices through which RAS action is accomplished.

The NERC SPS white paper suggests that the following RAS components should be covered by the single component failure requirement:

- Any single ac current source and/or related input to the RAS. Separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing should be considered an acceptable level of redundancy.
- Any single ac voltage source and/or related input to the RAS. Separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device should be considered an acceptable level of redundancy.
- Any single device used to measure electrical quantities used by the RAS.
- Any single communication channel and/or any single piece of related communication equipment used by the RAS.
- Any single computer or programmable logic device used to analyze information and provide RAS operational output.
- Any single element of the dc control circuitry that is used for the RAS, including breaker closing circuits.
- Any single auxiliary relay or auxiliary device used by the RAS.
- Any single breaker trip coil for any breaker operated by the RAS.
- Any single station battery or single charger, or other single dc source, where central monitoring is not provided for both low voltage and battery open conditions.

This list is consistent with the RAS "redundancy" practices presently accepted by most Regions. For its Type I and Type II schemes, NPCC uses a more extensive list which also includes restrictions, for example, on how control cables may be routed and forbids RAS components from separate (redundant) schemes from sharing control panels. The above "white paper" list is the acceptable minimum redundancy requirement under the terms of this standard.

Duplication of the listed components is a way to achieve redundancy and meet the "single component failure" requirement. For schemes performing distributed actions (e.g. load shedding or generation rejection at multiple locations), over-arming (providing extra corrective action to cover failure to operate of one critical component) can also be an effective option, as long as it does not compromise the performance of the system.

Breaker Failure and Single Component Failure (Gene)

Does the "single component failure" language also cover failure of any System component or Facility that the RAS uses to achieve its intended system impact? This is the interpretation of at least the NPCC and WECC Regions under the existing PRC-012-0, where the emphasis is on "meeting the performance requirements" of the TPL standards.

For example, these Regions apply the philosophy for the failure of a circuit breaker to operate (trip or close), regardless of the number of trip coils, if the operation of the breaker is required to achieve the System performance of the TPL requirements.

The following is from NPCC Regional Reliability Reference Directory # 7 Special Protection Systems (Dec 2013):

> 5.14 Provision for Breaker Failure Criteria
> Type I SPS shall include breaker failure protection for each circuit breaker whose operation is critical to the adequacy of the action taken by the SPS with due regard to the power system conditions this SPS is required to detect. The following are options for breaker failure protection.
>
> 5.15.1 A design which recognizes that the breaker has not achieved or will not achieve the intended function required by the SPS and which takes independent action to achieve that function. This provision needs not be duplicated and can be combined with conventional breaker failure schemes if appropriate.
>
> 5.15.2 Over-arming the SPS such that adequate action is taken even if a single breaker fails.
>
> 5.15.3 The redundancy afforded by actions taken by other independent schemes or devices.

The WECC Remedial Action Scheme Design Guide (2007) uses similar language:

> Failure of a circuit breaker to trip when called upon to trip by the RAS, even when equipped with dual trip coils, is considered a credible failure. Following are some common and acceptable methods to remediate such a failure:
>
> - Over-operate RAS action, e.g. trip extra generation equivalent to the largest generator or generation site which may fail to trip.
> - Initiate breaker failure protection. Breaker failure action usually operates additional breakers to isolate the stuck breaker while still performing the RAS action. Any additional tripping should not exacerbate the original power system problem that the RAS is designed to solve (e.g. avoid tripping additional lines. Refer to the System Performance summary at Table 1 of NERC Standard TPL-001-0 through TPL-004-0 and the WECC MORC.) The breaker failure scheme can also add significantly to the time for a RAS to operate, which may not be acceptable for a high speed transient stability RAS.

The scheme designer is not limited to these methods to address failure of a breaker to trip. However, it should be shown that failure of a breaker to trip (or close) will still result in acceptable system performance.

Furthermore, the failure of a circuit breaker to operate to accomplish its RAS function is not a recognized contingency under the TPL-001-4 standard, so is not counted as the "next" contingency for TPL compliance purposes. The closest contingency category is from Table 1, Category P5,

Category:	Multiple Contingency (Fault plus relay failure to operate)
Initial Condition:	Normal System:
Event	Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit

3. Transformer
4. Shunt Device
5. Bus Section

Fault Type: SLG

The original contingency that initiates RAS action may well be a SLG fault, but the "second" event directly involving the RAS in this discussion is a failure of a breaker to operate, not "a non-redundant relay protecting the faulted Element" and further identified in a footnote by specified function numbers: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). The "RAS" event may involve switching of any of the listed Elements, but the RAS would be attempting to accomplish its intended mitigation, not clearing a fault on that Element.

Response based RAS (those that take continuous action until a monitored system quantity recovers) typically do not require breaker failure protection initiation, since failure of any one action to take place will simply mean that the next action on the list will take place and the performance violation will still be mitigated, albeit one time step later. When studying the performance of a response based RAS, system planners will have to assume that the actual operating time of the RAS is one time step longer than designed.

Event based RAS which result in the closing of breakers (typically reactive insertion) must over-operate. Circuit breakers typically have only one close coil and there is no equivalent of breaker failure protection for closing actions. Therefore, when studying the performance of the RAS, the system planner must ensure that the RAS meets performance requirements for all contingencies, even if one breaker fails to close.

Event based RAS which result in the tripping of breakers will by default include the initiation of breaker failure protection. When studying the performance of the RAS, the system planner must ensure that the RAS meets System performance requirements, even if one breaker fails to trip. If the system topology is such that operation of breaker failure protection during a RAS event would exacerbate the performance violation, the system planner must then redefine their functional requirements for the RAS to state that breaker failure protection initiation must not be applied on that breaker, and ensure that the performance of the RAS is acceptable, if that breaker fails to trip, through other mitigating action.

In certain system topologies, and for certain RAS actions, the need to meet performance requirements in the event of a single breaker failure can be achieved by tripping extra breakers as part of the initial RAS action. For example, tripping of the HV and LV breakers of a transformer will interrupt power transfer through the transformer even if one breaker fails to trip. Similarly, tripping both ends of a line will also reliably interrupt power flow through the line, as long as the system meets performance requirements with the line left energized from one bus.

Attachment A – Standard Drafting Team Members

Project 2010-05.3 – Remedial Action Schemes		
	Participant	**Entity**
Chair	Gene Henneberg	NV Energy / Berkshire Hathaway Energy
Vice Chair	Bobby Jones	Southern Company
Member	Amos Ang	Southern California Edison
Member	Alan Engelmann	ComEd / Exelon
Member	Davis Erwin	Pacific Gas and Electric
Member	Sharma Kolluri	Entergy
Member	Charles-Eric Langlois	Hydro-Quebec TransEnergie
Member	Robert J. O'Keefe	American Electric Power
Member	Hari Singh	Xcel Energy
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Milena Yordanova (Legal Counsel)	NERC

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Remedial Action Schemes

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)

Background

In early 2011, NERC divided Project 2010-05: Protection Systems into three phases. Phase 1 addressed the Misoperations of Protection Systems and was adopted by the NERC Board of Trustees on August 14, 2014.

Phase 2 revised the definition of Remedial Action Scheme (RAS). A key element for the reliability of the Bulk-Power System is the correct identification and performance of Special Protection Systems (SPS) and RAS. The defined terms "Special Protection System" and "Remedial Action Scheme" are currently used interchangeably throughout the NERC Regions and in various Reliability Standards. To ensure consistent classification of systems that are RAS and application of Reliability Standards referencing the defined term, on February 3, 2015, NERC filed a petition with FERC, proposing revisions to the existing definition of RAS and corresponding changes in several Reliability Standards. NERC's goal is to gradually modify all of the NERC Reliability Standards to incorporate the use of only a single term Remedial Action Scheme and eliminate the use of the term Special Protection Systems.

Phase 3 of this Project is intended to address all aspects of RAS and SPS contained in the RAS/SPS-related Reliability Standards and regional practices. The existing regional practices lack the specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the ERO Enterprise. Therefore, Phase 3 of the Project[1] is intended to develop an uniform standard to address all aspects of SPS and RAS, including planning, coordination and design, analysis of operations, and testing and maintenance of PSP/RAS, among other issues.[2] The Project also addresses in part four recommendations related to identification and coordination of SPS included in the joint FERC-NERC Southwest Power Outage Report.

Requested Approval

- PRC-012-2 – Remedial Action Schemes

[1] There is no FERC directive associated with this Project. However, in FERC Order No. 693 (March 16, 2007), FERC identified PRC-012-0, PRC-013-0, and PRC-014-0 as "fill-in-the-blank" standards and did not approve or remand them. These Reliability Standards are applicable to the Regional Reliability Organizations (RROs), assigning the RROs the responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of RAS/SPS. These Reliability Standards are used as a basis for drafting PRC-012-2.

[2] See Standards Authorization Request Form at 2. Available at: http://www.nerc.com/pa/Stand/Prjct201005_2SpclPrtctnSstmPhs2/SPS_SAR_02042014.pdf

Requested Withdrawal of Reliability Standards

- PRC-012-0 - Special Protection System Review Procedure
- PRC-013-0 - Special Protection System Database
- PRC-014-0 - Special Protection System Assessment

Requested Retirement of Reliability Standards

- PRC-015-0 - Special Protection System Data and Documentation
- PRC-016-0.1 - Special Protection System Misoperations

Prerequisite Approvals

- Revised Definition of "Remedial Action Scheme" currently pending FERC review

New or Revisions to Defined Terms in the NERC Glossary

- None

Definition(s) Used in Standard

Applicable Entities

- Reliability Coordinator
- Transmission Planner
- RAS-owner – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
- RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider designated to represent all owners of the RAS

Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

Effective Dates for Existing Remedial Action Schemes

The proposed Reliability Standard PRC-012-2, as applied to existing RAS, shall become effective on the later day of 1) the day after the revised definition of Remedial Acton Scheme becomes effective or 2) the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where

Commented [MY1]: Al, the current definition of SPS states "Also called Remedial Action Scheme." Do you want to include a change in the definition as well, in case we decide not to request changes to the standards using SPS? I think this was the original plan. We can include a reference " See RAS"

Commented [MY2]: I don't think we have some specific definitions not included in the Glossary.

Commented [MY3]: This is in the event we would like to rework the Standards that reference SPS.

Commented [MY4]: revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority

I think this gives us 12 months under any circumstance.

approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Newly Classified Remedial Action Schemes

The proposed Reliability Standard PRC-012-2, as applied to newly classified RAS, shall become effective on the later day of 1) the first day of the first calendar quarter that is twelve (12) months after the effective date of the revised definition of Remedial Acton Scheme or 2) the first day of the first calendar quarter that is twenty four (24) months after the date the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Commented [MY5]: 12+12 should be 24.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft 1 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS/SPS-related standards. This draft of PRC-012-2 contains nine (9) requirements and measures, and the associated rationale boxes and corresponding technical guidelines. There are also three (3) attachments within the draft standard incorporated via references in the requirements. This draft of PRC-012-2 is posted for a 45-day initial formal comment period and 10-day ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014

Anticipated Actions	Date
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with ballot	July 2015
10-day final ballot	October 2015
NERC Board (Board) adoption	November 2015

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Planner
     - **4.1.3.** RAS-owner – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
     - **4.1.4.** RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider designated to represent all owners of the RAS
   - **4.2. Facilities:**
     - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See Implementation Plan for Project 2010-05.3 PRC-012-2

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) must be completed prior to implementation. A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates the RAS-entity provide them to the reviewing Reliability Coordinator (RC). A specific time period for the RAS-entity to provide Attachment 1 to the reviewing RC is not necessary because an expeditious submittal is in the self-interest of the RAS-owner(s) to effect a timely implementation. The RC responsible for the review will be the RC that coordinates the area where the RAS is located. In cases where a RAS crosses multiple RC Area boundaries, each affected RC would be responsible for conducting either individual reviews or a coordinated review.

R1. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 to the reviewing Reliability Coordinator(s) to enable RAS review per Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence is a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: Requirement R2 mandates that the Reliability Coordinator (RC) perform a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) in its RC area.

The RC is the functional entity best-suited to perform the RAS reviews because it has a wide-area perspective of reliability that includes awareness of reliability issues in its neighboring RC Areas. This wide-area purview provides continuity in the review process and better facilitates the coordination of interactions among separate RAS as well as the coordination of interactions among RAS and other protection and control systems. The selection of the RC also minimizes the possibility of a “conflict of interest” that could exist because of business relationships among the RAS-Entity, Planning Coordinator (PC), Transmission Planner (TP), or other entity that are often involved in the planning or implementation of a RAS. The PC is included as part of the review team, though without decision authority, to make sure that Planning horizon concerns are adequately addressed. The RC may request aid in RAS reviews from other parties such as the Planning Coordinator or regional technical groups; however, the RC will retain the responsibility of compliance with this requirement.

Attachment 2 of this standard is a checklist provided to the RC to assist in identifying important design and implementation aspects of RAS, and in facilitating consistent reviews for each RAS submitted. The time frame of four full calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the Region(s) in which it is located.

R2. For each RAS submitted pursuant to Requirement R1, each reviewing Reliability Coordinator shall, within four full calendar months of receipt of Attachment 1 materials, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to the RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, date-stamped reports, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: Requirement R3 mandates the RAS-entity address all issues identified by the Reliability Coordinator (RC) during the RAS review, and obtain approval from the RC that the RAS implementation can proceed. This interaction promotes reliability by minimizing the introduction of inadvertent actions (risks) to the BES. A specific time period for the RAS-entity to respond to the RC's review is not necessary because an expeditious response is in the self-interest of the RAS-owner(s) to effect a timely implementation. The review by the RC is intended to identify reliability issues that must be resolved before the RAS can be put in service. The reliability issues could involve dependability, security, or both. A more detailed explanation of dependability and security is included in the Supplemental Materials section of the standard.

R3. Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator, prior to placing a new or functionally modified RAS in-service or retiring an existing RAS. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, date-stamped documentation and date-stamped communications with the reviewing Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that a evaluation of each RAS be performed at least once every 60 full calendar months. The purpose of periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as BES performance following an inadvertent RAS operation. This periodic evaluation is needed due to possible changes in system topology and operating conditions that may

have occurred since the previous RAS evaluation (or initial review) was completed. Sixty (60) full calendar months was selected as the maximum time frame for the evaluation based on the time frames for similar requirements in Reliability Standards PRC-006-1, PRC-010-1, and PRC-014-1. The RAS evaluation can be performed sooner if it is determined that material changes to system topology or system operating conditions that could potentially impact the effectiveness or coordination of the RAS have occurred since the previous RAS evaluation or will occur before the next scheduled evaluation. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is adequate; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Parts 4.1, 4.2, 4.3) are planning analyses which involve modeling of the interconnected transmission system; consequently, the Transmission Planner (TP) is the functional entity best qualified to perform the analyses. To promote reliability, the TP is required to provide the RAS-owner(s) and the Reliability Coordinator(s) with the results of each evaluation.

R4. Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60 full calendar months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. The RAS mitigates the System condition(s) or contingency(ies) for which it was designed.

4.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.3. The possible inadvertent operation of the RAS resulting from any single RAS component inadvertent operation satisfies all of the following:

4.3.1. The BES shall remain stable.

4.3.2. Cascading shall not occur.

4.3.3. Applicable Facility Ratings shall not be excedded.

4.3.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.3.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

4.4. A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS was designed.

M4. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation of the analyses comprising the evaluation(s) of each RAS and date-stamped communications with the RAS-owner(s) and the Reliability Coordinator(s) in accordance with Requirement R4.

Rationale for Requirement R5: The correct operation of a RAS is important to maintaining the reliability and integrity of the Bulk Electric System (BES). Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS performance was consistent with its intended functionality and design. The 120 calendar day time frame aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation.

The RAS-owner(s) will need to collaborate with its associated Transmission Planner(s) to analyze the RAS performance and System response (Parts 5.1, 5.2, 5.3, 5.4). To promote reliability, the RAS-owner(s) is required to provide the results of performance analyses to its Reliability Coordinator(s).

R5. Each RAS-owner(s) and its associated Transmission Planner(s) shall, within 120-calendar days of a RAS operation or failure of a RAS to operate when expected, analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to its reviewing Reliability Coordinator(s). The analysis shall determine whether the: *[Violation Risk Factor:Medium] [Time Horizon:Operations Planning]*

5.1. System events and/or conditions appropriately triggered the RAS.

5.2. RAS responded as designed.

5.3. RAS was effective in mitigating BES performance issues it was designed to address.

5.4. RAS operation resulted in any unintended or adverse power System response.

M5. Acceptable evidence may include, but is not limited to, date-stamped documentation detailing the RAS operational performance analysis in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies identified either in the periodic RAS evaluation conducted by the Transmission Planner in Requirement R4, or in the analysis conducted by the RAS-owner(s) pursuant to Requirement R5 are likely to pose a reliability risk to the BES due to the impact of either a RAS operation or incorrect operation. To avoid this reliability risk, Requirement R6 mandates that the RAS-owner(s) develop a Corrective Action Plan that establishes the mitigation methods and timetable to address the deficiency. If the Corrective Action Plan requires that a functional change be made to

a RAS, the RAS-owner(s) will need to submit information identified in Attachment 1 to the RC(s) for review prior to placing RAS modifications in service per Requirement 1.

Depending on the complexity of the issues, development of a CAP may require study, engineering, or consulting work. A timeframe of six full calendar months is specified to allow enough time for RAS-owner collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonabe time. A RAS deficiency may require the Reliability Coordinator or Transmission Operator to impose operating restrictions so the system can operate in a reliable way until the RAS deficiency is resolved. Such operating restrictions will incent the RAS-owner to resolve the issue as quickly as possible.

R6. Within six full calendar months of being notified of a deficiency in its RAS, based on the evaluation performed pursuant to Requirement R4, or of identifying a performance deficiency in its RAS based on the analysis performed pursuant to Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan and submitting it to its reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

M6. Acceptable evidence may include, but is not limited to, a date-stamped Corrective Action Plan and date-stamped communications with each reviewing Reliability Coordinator in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates the RAS-owner(s) implement a Corrective Action Plan submitted to address any identified deficiency(ies) found in conjunction with the periodic evaluation pursuant to Requirement R4, and any identified incorrect operation found by the analysis of an actual RAS operation pursuant to Requirement R5. Since the NERC Glossary of Terms defines a Corrective Action Plan (CAP) as "A list of actions and an associated timetable for implementation to remedy a specific problem", the implemention of a properly developed CAP submitted pursuant to Requirement R6 ensures that any identified deficiency(ies) or incorrect operation(s) are addressed by following a documented schedule of actions.

R7. For each CAP submitted pursuant to Requirement R6, each RAS-owner shall implement the CAP and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Acceptable evidence may include, but is not limited to, dated documentation (electronic or hardcopy format) such as Corrective Action Plans, project or work management program records, settings sheets, work orders, and maintenance records that document the implementation of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that

periodic functional testing of RAS is performed. A functional test provides an overall confirmation of the RAS's ability to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005. The component testing focus of PRC-005 is fundamentally different from functional testing required here. Functional testing verifies RAS performance rather than straightforward component health verification. The six calendar year interval was selected because it coincides with the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005-3, thus providing entities the opportunity to align maintenance of Protection System Components with functional RAS testing, if scheduled outages are necessary. Extending to longer intervals could expose a latent failure, creating a BES reliability risk. The RAS-owner is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and expected operation. Periodic functional testing promotes the identification of changes in System infrastructure that could have introduced latent failures into the RAS. Functional testing may be accomplished with end-to-end testing or a segmented approach. Each segment of a RAS should be tested but overlapping segments can be tested individually negating the need for complex maintenance schedules and outages. A correct operation of a RAS qualifies as a functional test as long as all segments operate. Should an event operate less than the full RAS, the segments without an operation will need a functional test within the 6 year interval to be compliant with this Requirement.

R8. At least once every six calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. *[Violation Risk Factor: High] [Time Horizon:Long-term Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped documentation of the functional testing.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator's area. The database enables the RC to provide other entities the ability to obtain high level information on existing RAS that can potentially impact the entities' operational and/or planning activities. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entity identified in the database contact information. The Reliability Coordinator (RC) is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review.

R9. Each Reliability Coordinator shall update a RAS database containing the information in Attachment 3 at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a RAS database was maintained in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

> The applicable entity shall keep data or evidence to show compliance with requirements **(DELETE GREEN TEXT PRIOR TO PUBLISHING) Add requirements as appropriate for this standard. This section is only for those requirements that do not have the default data retention.** since the last audit.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.				The RAS-entity failed to submit the information identified in Attachment 1 to the reviewing Reliability Coordinator(s) prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.
R2.			The reviewing Reliability Coordinator failed to complete the review and provide the written feedback within four full calendar months or the mutually agreed upon schedule in accordance with Requirement R2.	The reviewing Reliability Coordinator failed to perform the review in accordance with Requirement R2. OR The reviewing Reliability Coordinator failed to provide the written feedback in accordance with Requirement R2.
R3.				The RAS-entity failed to obtain approval from each reviewing Reliability Coordinator prior to placing

				a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Transmission Planner performed the evaluation in accordance with Requirement R4, in greater than 60 full calendar months but less than 61 full calendar months.	The Transmission Planner performed the evaluation in accordance with Requirement R4, in greater than 61 full calendar months but less than 62 full calendar months.	The Transmission Planner performed the evaluation in accordance with Requirement R4, in greater than 62 full calendar months but less than 63 full calendar months. OR The Transmission Planner performed the evaluation in accordance with Requirement R4 but failed to evaluate one of the Parts.	The Transmission Planner performed the evaluation in accordance with Requirement R4, in greater than 63 full calendar months or failed to provide the evaluation at all. OR The Transmission Planner performed the evaluation in accordance with Requirement R4 but failed to evaluate two or more of the Parts. OR The Transmission Planner performed the evaluation in accordance with Requirement R4 but failed to provide the results to the RAS-owner(s) and the reviewing Reliability Coordinator(s).

R5.	The responsible entity performed the analysis in greater than 120 calendar days but no more than 130 calendar days in accordance with Requirement R5.	The responsible entity performed the analysis in greater than 130 calendar days but no more than 140 calendar days in accordance with Requirement R5.	The responsible entity performed the analysis in greater than 140 calendar days but no more than 150 calendar days in accordance with Requirement R5. OR The responsible entity performed the analysis in accordance with Requirement R5 but failed to address one of the Parts.	The responsible entity performed the analysis in greater than 150 calendar days. OR The responsible entity failed to provide the analysis in accordance with Requirement R5. OR The responsible entity performed the analysis in accordance with Requirement R5 but failed to address two or more of the Parts. OR The responsible entity performed the analysis in accordance with Requirement R5 but failed to provide the results to the reviewing Reliability Coordinator(s).
R6.	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator in	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator in	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator in	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator in

	accordance with Requirement R6 but was late by less than or equal to 10 calendar days.	accordance with Requirement R6 but was late by more than 10 calendar days but less than or equal to 20 calendar days.	accordance with Requirement R6 but was late by more than 20 calendar days but less than or equal to 30 calendar days.	accordance with Requirement R6 but was late by more than 30 calendar days or failed to submit to its reviewing Reliability Coordinator. OR The RAS-owner failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-owner implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R7.			The RAS-owner failed to implement a CAP in accordance with Requirement R7.
R8.				The RAS-owner failed to perform the functional test for a RAS within the six calendar years in accordance with Requirement R8.
R9.	The Reliability Coordinator updated the database in accordance with Requirement R9 but was late by less than or equal to 30 calendar days.	The Reliability Coordinator updated the database in accordance with Requirement R9 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The Reliability Coordinator updated the database in accordance with Requirement R9 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The Reliability Coordinator updated the database in accordance with Requirement R9 but was late by more than 90 calendar days. OR

				The Reliability Coordinator failed to update the database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents. **(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**

Version History **(DELETE GREEN TEXT PRIOR TO PUBLISHING) Note: All version histories' content should be carried over to next generation.**

Version	Date	Action	Change Tracking
		(DELETE GREEN TEXT PRIOR TO PUBLISHING) Project #: action completed	**(DELETE GREEN TEXT PRIOR TO PUBLISHING) New, Errata, Revisions, Addition, Interpretation, etc.**

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important RAS information for each new or functionally modified[1] RAS that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1. If an item on this list does not apply to a specific RAS, a response of NA or Not Applicable for that item is appropriate. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, the RAS entity must provide a summary of the previously approved functionality. The RC may request additional information on any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
   [Reference NERC Reliability Standard PRC-012, Requirements R5 and R7]

4. Initial data to populate the RAS database:
   1. RAS name
   2. RAS-entity and contact information
   3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60 full calendar month (Requirement R4) evaluation date; and, date of retirement, if applicable
   4. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)
   5. Description of the contingencies or System conditions for which the RAS was designed (initiating conditions)
   6. Corrective action taken by the RAS
   7. Any additional explanation relevant to high level understanding of the RAS

II. Functional Description and Transmission Planning Information

1. Contingencies and system conditions that the RAS is intended to remedy.
   [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

[1] Functionally Modified:
Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

2. The actions to be taken by the RAS in response to disturbance conditions.
   [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), system conditions, and contingencies analyzed on which the RAS design is based, and when those technical studies were performed.
   [Reference NERC Reliability Standard PRC-014, R3.2]

4. Information regarding any future system plans that will impact the RAS.
   [Reference NERC Reliability Standard PRC-014, R3.2]

5. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component inadvertent operation satisfies all of the following:
   - The BES shall remain stable.
   - Cascading shall not occur.
   - Applicable Facility Ratings shall not be exceeded.
   - BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   - Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator

   [Reference NERC Reliability Standard PRC-012, R1.4]
6. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
   [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

7. Identification of other affected RCs.

III. Implementation

1. Documentation describing the equipment used for detection, telecommunications, transfer trip, logic processing, and monitoring, whichever are applicable.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

4. Documentation showing that a single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS was designed. The documentation should describe or illustrate how the implementation design achieves this objective.
   [Reference NERC Reliability Standard PRC-012, R1.3]

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Commented [GH1]: Do we need this bullet? Doesn't hurt.

Commented [GH2]: 2 alternate wording options

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify pursuant to Requirement R2 for each new or functionally modified[2] RAS. The RC review is not limited to the checklist items and the RC may request additional information on any reliability issue related to the RAS.

I. DESIGN

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.

2. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.

3. The RAS avoids adverse interactions with other RAS, Protection Systems, control systems, and Operating Procedures.

4. The effects of RAS incorrect operation, including inadvertent operation and failure to operate (if non-operation for RAS single component failure is acceptable), have been identified.

5. The Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component inadvertent operation satisfies all of the following:
   - The BES shall remain stable.
   - Cascading shall not occur.
   - Applicable Facility Ratings shall not be exceeded.
   - BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   - Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator

6. The effects of future BES modifications on the design and operation of the RAS, where applicable, have been identified.

II. IMPLEMENTATION

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).

2. The timing of RAS action(s) is appropriate to its BES performance objectives.

3. A single component failure in a RAS does not prevent the BES from meeting the same

[2] Functionally Modified:
Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

performance requirements as those required for the events and conditions for which the RAS was designed.

4. The RAS design facilitates periodic testing and maintenance.
5. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.
6. RAS automatic arming, if applicable, has the same degree of redundancy as the RAS itself.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate Planning justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. RAS-entity and contact information.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60 full calendar-month (Requirement R4) evaluation date; and, date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
5. Description of the contingencies or System conditions for which the RAS was designed (initiating conditions).
6. Corrective action taken by the RAS.
7. Any additional explanation relevant to high level understanding of the RAS.

Supplemental Material

Technical Justifications for Requirements

Requirement R1:

Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) must be completed prior to implementation. A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC responsible for the review will be the RC that coordinates the area where the RAS is located. In cases where a RAS crosses multiple RC Area boundaries, each affected RC would be responsible for conducting either individual reviews or a coordinated review.

Requirement R2:

Requirement R2 mandates that the Reliability Coordinator (RC) perform a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) in its RC area.

The RC is the functional entity best-suited to perform the RAS reviews because it has a wide-area perspective of reliability that includes awareness of reliability issues in its neighboring RC Areas. This wide-area purview provides continuity in the review process and better facilitates the coordination of interactions among separate RAS as well as the coordination of interactions among RAS and other protection and control systems. The selection of the RC also minimizes the possibility of a “conflict of interest” that could exist because of business relationships among the RAS-Entity, Planning Coordinator (PC), Transmission Planner (TP), or other entity that could be involved in the planning or implementation of a RAS. The RC may designate a third party to conduct the RAS reviews; however, the RC will retain the responsibility of compliance with this requirement.

Attachment 2 of this standard is a checklist provided to the RC to assist in identifying important design and implementation aspects of RAS, and in facilitating consistent reviews for each RAS submitted. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the Region(s) in which it is located

Requirement R3:

Requirement R3 mandates the RAS-entity address all reliability-related issues identified by the Reliability Coordinator (RC) during the RAS review, and obtain approval from the RC that the RAS implementation can proceed. This interaction promotes reliability by minimizing the introduction of inadvertent actions (risks) to the BES. A specific time period for the RAS-entity

to respond to the RC's review is not necessary because an expeditious response is in the self-interest of the RAS-owner(s) to effect a timely implementation. The review by the RC is intended to identify reliability issues that must be resolved before the RAS can be put in service. The reliability issues could involve dependability, security, or both.

Dependability is a component of reliability and is the measure of a device's certainty to operate when required. Since RAS are usually installed to meet performance requirements of NERC standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC performance standards if the critical contingency(ies) or System conditions occur. This risk is usually mitigated by installing an appropriate level of redundancy as part of the RAS so that it will still accomplish its intended purpose even while experiencing a single component failure.

Security is a component of reliability and is the measure of a device's certainty not to operate falsely. False, or inadvertent operation of a RAS results in taking some programmed action that the RAS would take for a correct operation, but without either the appropriate arming conditions or occurrence of the critical contingency(ies) or System conditions expected to trigger the RAS action. Typically these actions include shedding load or generation or re-configuring the System. This inadvertent action is undesirable in the absence of the critical System conditions and may, on its own, put the System in a less secure state. The standard allows an impact up to the level that would occur for a correct operation. If this risk needs to be further mitigated, voting schemes have been successfully used in the industry for both RAS and Protection systems.

Either type of reliability issue must be resolved before placing the RAS in service to avoid placing the System at unacceptable risk. The RAS-entity (and any other RAS-owner) or the RC may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in favor of reliability, and the RC has the final decision.

Requirement R4:

Requirement R4 mandates that an evaluation of each RAS be performed at least once every 60 full calendar months. The purpose of periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that BES performance requirements for inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is needed because changes in system topology or operating conditions that have occurred since the previous RAS evaluation (or initial review) was completed may change the effectiveness of a RAS or the the way it interacts with and impacts the BES.

Sixty (60) full calendar months was selected as the maximum time frame for the evaluation based on the time frames for similar requirements in Reliability Standards PRC-006-1, PRC-010-1, and PRC-014-1. The RAS evaluation can be performed sooner if it is determined that material changes to system topology or system operating conditions that could potentially impact the effectiveness or coordination of the RAS have occurred since the previous RAS evaluation or will occur before the next scheduled evaluation. The periodic RAS evaluation will typically lead to

one of the following outcomes: 1) affirmation that the existing RAS is adequate; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Parts 4.1, 4.2, 4.3, 4.4) are planning analyses which involve modeling of the interconnected transmission system to assess BES performance; consequently, the Transmission Planner (TP) is the functional entity best qualified to perform the analyses. To promote reliability, the TP is required to provide the RAS-owner(s) and the Reliability Coordinator(s) with the results of each evaluation.

Requirements for inadvertent RAS operation (4.3) and single component failure (4.4) are reviewed by the RC before a new or modified RAS is placed in service, and are typically satisfied with specific design considerations. Although the scope of the 60 month evaluation does not include a new design review, it is possible that a design which previously satisfied requirements for inadvertent RAS operation and single component failure may fail to do so at a later point in time, and must be evaluated with respect to the current System. For example, System changes could occur impacting the amount of load tripped by a particular RAS output. Inadvertent activation of that output could begin tripping too much load, resulting in violations of Facility Ratings; alternatively, a RAS designed to "over-trip" more load than necessary in order to compensate for single component failure may no longer trip enough load at affected locations, resulting in unacceptable BES performance if one of the loads failed to trip.

Requirement R5:

The correct operation of a RAS is important to maintaining the reliability and integrity of the Bulk Electric System (BES). Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS performance was consistent with its intended functionality and design. The 120 calendar day time frame aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation.

The RAS-owner(s) will need to collaborate with its associated Transmission Planner(s) to analyze the RAS performance and System response (Parts 5.1, 5.2, 5.3, 5.4). To promote reliability, the RAS-owner(s) is required to provide the results of performance analyses to its Reliability Coordinator(s).

Requirement R6:

Deficiencies identified either in the periodic RAS evaluation conducted by the Transmission Planner in Requirement R4, or in the analysis conducted by the RAS-owner(s) pursuant to Requirement R5 are likely to pose a reliability risk to the BES due to the impact of either a RAS operation or incorrect operation. To avoid this reliability risk, Requirement R6 mandates that the RAS-owner(s) develop a Corrective Action Plan that establishes the mitigation methods and timetable to address the deficiency. If the Corrective Action Plan requires that a functional change be made to a RAS, the RAS-owner(s) will need to submit information identified in Attachment 1 to the RC(s) for review prior to placing RAS modifications in service per Requirement 1.

Supplemental Material

Depending on the complexity of the issues, development of a CAP may require study, engineering, or consulting work. A timeframe of six full calendar months is specified to allow enough time for RAS-owner collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonabe time. A RAS deficiency may require the Reliability Coordinator or Transmission Operator to impose operating restrictions so the system can operate in a reliable way until the RAS deficiency is resolved. Such operating restrictions will incent the RAS-owner to resolve the issue as quickly as possible.

A Corrective Action Plan (CAP) documents a RAS performance deficiency, the strategy to correct the deficiency with identified tasks, the responsible party assigned to each task, and the targeted completion date(s).

The following are examples situations of when a CAP is required:

a) A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations. The RAS did not operate as designed.
b) Periodic planning assessment reveals RAS changes are necessary to satisfy performance effectiveness or to correct identified coordination issues.
c) Equipment failure detrimentally affects the dependability or security of the RAS.

Requirement R7:

Requirement R7 mandates the RAS-owner(s) implement a Corrective Action Plan submitted to address any identified deficiency(ies) found in conjunction with the periodic evaluation pursuant to Requirement R4, and any identified incorrect operation found by the analysis of an actual RAS operation pursuant to Requirement R5. Since the NERC Glossary of Terms defines a Corrective Action Plan (CAP) as “A list of actions and an associated timetable for implementation to remedy a specific problem”, the implemention of a properly developed CAP submitted pursuant to Requirement R6 ensures that any identified deficiency(ies) or incorrect operation(s) are addressed by following a documented schedule of actions.

Requirement R8:

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as PLCs) and to verify the overall performance of the scheme through functional testing. Functional tests validate RAS operation by ensuring system states are detected and processed, and that actions taken by the controls are correct and within the expected time frames using the in-service settings and logic. Since functional testing is aimed at overall RAS performance, the SDT chose to address RAS testing in PRC-012-2 rather than include it in the component focused PRC-005 Standard.

Functional testing can be difficult to schedule and perform, but it is critical to ensure the proper functioning of RAS and, therefore, BES reliability. Since the functional test operates the Scheme under controlled conditions with known system states and expected results, testing and result analysis can be performed without impact to the BES. The RAS-owner is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and expected operation. Periodic testing provide the RAS owner assurance that latent failures are not present in the RAS design and implementation, and also promotes identification of changes in System infrastructure may have introduced latent failures.

Supplemental Material

The six calendar year interval coincides with the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005-3, but is greater than the annual or bi-annual testing used in many Regions. The choice of this interval also considered risks to BES reliability as a latent failure is more likely to cause an incorrect operation the longer it remains undetected.. The SDT suggests that entities design their functional testing program for this Requirement include the Table activities from PRC-005 to avoid duplication for components common to both Standards; functional testing done for PRC-012 R8 could satisfy the Requirements of PRC-005.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is acceptable and may be used, but is not be feasible for many RAS. If end-to-end testing is not possible, a segmented functional testing approach is recommended. The segments can be tested individually negating the need for complex maintenance schedules. In addition, the SDT accepts that actual RAS operation(s) can be used to fulfill the functional testing Requirement. If a RAS does not operate in its entirety during a system event or system conditions do not allow a complete end-to-end system test, the segmented approach can be used to fulfill this Requirement. The goal of a functional test procedure is inclusion of all conditions the RAS uses for detection, arming, operating, and data collection, processing via the logic and infrastructure of a RAS, addressing the system condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within a 6 year interval to demonstrate compliance with the Requirement.

As an example, consider a RAS implemented using one control component not addressed in the Protection System definition but used regularly in RAS: a programmable logic controller (PLC). The PLC does not meet the definition of a Protection System and will have no required maintenance as part of PRC-005-2. In this simplified example, the PLC based RAS is sensing system conditions such as loading and line status from many locations, and implements breaker tripping at multiple locations to alleviate an overload condition. At one of these locations, a line protective relay, included in a RAS-owners PSMP as a Protection System component, is used to operate a breaker upon receipt an operate command from the remote RAS PLC. The relay sends data and receives commands from the RAS PLC over non-Protection System communications infrastructure. A functional test would simulate via external signals to the PLC system conditions requiring an operate command to the protective relay, operating its associated breaker. This action verifies RAS action, verifies PLC control logic, and verifies of RAS communications from PLC to relay. To complete this portion of a functional test, application of external testing signals to the protective relay, verified at the PLC are necessary to confirm full functioning of the RAS zone being tested. As this example RAS is implemented across several locations, the testing described would only constitute one segment of a full RAS functional test. The remaining segments in the RAS design would also require testing.

IEEE C37.233, “IEEE Guide for Power System Protection Testing,” section 8 (particularly 8.3-8.5), provides a very good overview of functional testing. The following opens section 8.3:

> “Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs,

communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.

The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of contingencies, and to verify scheme performance as well as the inputs and outputs."

Requirement R9:

The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator's area. The database enables the RC to provide other entities the ability to obtain high level information on existing RAS that can potentially impact the entities' operational and/or planning activities. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entity identified in the database contact information. The Reliability Coordinator (RC) is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review.

Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a remedial action scheme (RAS) it is necessary for the RAS owner(s) to provide a detailed list of information describing the RAS to the reviewing Reliability Coordinator (RC). While information may be needed from all owners of a RAS, a single RAS-owner (designated as the (RAS-entity)) is usually assigned the responsibility of compiling the RAS data and presenting it to the RC(s) review team. Other RAS-owners may participate in the review, if they choose.

The necessary data ranges from a general overview of the scheme to results of Transmission Planning studies that illustrate System performance before and after the RAS goes into service, as well as expected performance for unusual conditions, and whether certain adverse reliability impacts may occur. Possible adverse interactions, i.e. coordination between the RAS and other RAS and protection and control systems will be examined. This review can include wide ranging electrical design issues involving the specific hardware, logic, telecommunications and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[3] RAS that the RAS-entity shall document and provide to the Reliability Coordinator (RC) for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to the reviewers if the RAS entity provides a summary of the previously approved RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

    - Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See “RAS Design”, below, for additional information.
    - Provide a single line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

[3]Functionally Modified:
Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
   [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]
   - The CAP is required if the periodic evaluation pursuant to Requirement R4, or the analysis of an actual RAS operation pursuant to Requirement R6 identified any performance deficieny(ies).

II. Functional Description and Transmission Planning Information

1. Contingencies and system conditions that the RAS is intended to remedy.
   [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]
   - The System conditions which would result if no RAS action occurred should be identified.
   - Include a description of the System conditions which should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical system contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.
   - Event based RAS are triggered by specific contingencies that initiate mitigating action. These contingencies should be identified. Condition based RAS may also be initiated by specific contingencies, but this is not always required.

2. The actions to be taken by the RAS in response to disturbance conditions.
   [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]
   - Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies should include information such as the study year(s), system conditions, and contingencies analyzed on which the RAS design is based, and when those technical studies were performed.
   [Reference NEC Reliability Standard PRC-014, R3.2]
   - Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements.
4. Information regarding any future system plans that will impact the RAS.
   [Reference NERC Reliability Standard PRC-014, R3.2]
   - The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range Plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.
5. Documentation showing that inadvertent operation of the RAS satisfies the same performance requirements as those required for the contingency for which it was designed

or, if no performance requirements apply, the inadvertent operation of the RAS satisfies the requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4, or its successor.
[Reference NERC Reliability Standard PRC-012, R1.4]

6. An evaluation indicating that the RAS avoids adverse interactions with other RAS, and protection and control systems.
   [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]
   - RAS are complex schemes that typically take action which trips load or generation or re-configures the system. Many RAS depend on sensing specific system configurations to determine whether they need to arm or take actions. Examples include: overlapping actions among RAS that may have the potential to result in cascading, unless coordinated, RAS that reconfigure the System also change the available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

7. Identification of other affected RCs.
   - This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the equipment used for detection, telecommunications, transfer trip, logic processing, and monitoring, whichever are applicable.

   Logic Processing
   - All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

   - Platforms that have been used reliably and successfully, include programmable logic controllers (PLCs) in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

   Communications Channels
   - Communication channels used for sending and receiving RAS information between sites and/or transfer trip devices must meet at least the same criteria as for other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

   - The scheme logic should be designed so that loss of the channel, noise, or other channel failure will not result in a false operation of the scheme.

- It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS owner, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment must be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall be taken place upon failure.
- Communication channels shall be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities shall be identified with a common name at all terminals.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Detection and initiating devices must be designed to be as secure as possible. The following discussion identifies several types of devices that have been used as disturbance detectors:

   - Line open status (event detectors),
   - Protective relay inputs and outputs (event and parameter detectors),
   - Transducer and IED (analog) inputs (parameter and response detectors),
   - Rate of change (parameter and response detectors).

   Several methods to determine line open status are in common use, often in combination:

   - Auxiliary switch contacts from circuit breakers and disconnect switches (52b, 89b),
   - Undercurrent detection (a low level indicates an outage),
   - Breaker trip bus monitoring, and
   - Other detectors such as angle, voltage, power, frequency, rate of change of these, out of step, etc.

3. Documentation showing that any device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

   - In this context, a multifunction device (e.g. microprocessor-based relay) is a single device that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when is being maintained. The following list outlines concerns to be addressed when the RAS function is applied in the same microprocessor-based relay as the protection function:

     - a) Describe how the multifunction device is applied in the RAS.
     - b) Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

- c) Describe the procedures used to isolate the RAS function from other functions in the device.
- d) Describe the procedures used when each multifunction device is removed from service and whether any other coordination with other protection is required.
- e) Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.
- f) Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.
- g) Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

o Other devices usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation showing that a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the System events and conditions for which the RAS was designed. The documentation should describe or illustrate how the implementation design achieves this objective.
   [Reference NERC Reliability Standard PRC-012, R1.3]

The critical part of PRC-012 R1.3 philosophy is that a RAS should be designed so that a "single [RAS] component failure … does not prevent … meeting the performance requirements defined in Reliability Standards". The philosophy regarding "single component failure" from PRC-012-0 is carried over in to this standard. Redundancy is one way to implement the "single component failure" philosophy but other methods are acceptable.

The following list are examples of RAS components that could be considered in the single component failure analysis:

- Any single ac secondary current or voltage source and/or related inputs to the RAS.
- Any single device used to measure electrical quantities used by the RAS.
- Any single communication channel and/or any single piece of related communication equipment used by the RAS.
- Any single computer or programmable logic device used to analyze information and provide RAS operational output.
- Any single element of the dc control circuitry that is used for the RAS, including breaker closing circuits.
- Any single auxiliary relay or auxiliary device used by the RAS.
- Any single breaker trip coil for any breaker operated by the RAS.
- Any single station battery or single charger, or other single dc source, where central monitoring is not provided for both low voltage and battery open conditions.

Duplication of the listed components is a way to achieve redundancy and meet the "single component failure" requirement. For schemes performing distributed actions (e.g. load shedding or generation rejection at multiple locations), over arming (providing extra corrective action to cover failure to operate of one critical component) can also be an effective option, as long as it does not compromise the performance of the system. Other coordinated Protection Systems, such as breaker failure, may be used as long as the System performance resulting from breaker failure is still acceptable under the original contingency the RAS was designed to mitigate

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Supplemental Material

Technical Justifications for Attachment 3 Content
Database Information

Attachment 3 contains the minimum information the RC must consolidate into its database for each RAS in its area.

1. RAS name.
   - The usual name used to identify the RAS.

2. RAS-entity and contact information.
   - A reliable phone number or email address should be included to contact the RAS-entity if more information is needed (e.g. modeling information per requirement R11). At a minimum, the name of the RAS-entity responsible for the RAS information.

3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60 full calendar-month (Requirement R4) evaluation date; and, date of retirement, if applicable.
   - Specify each applicable date.

4. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   - A short description of the reason for installing the RAS is sufficient, as long as the main system issues addressed by the RAS can be identify by someone with a reliablilty need.

5. Description of the contingencies or System conditions for which the RAS was designed (initiating conditions).
   - A high level summary of the conditions/contingencies is expected. Not all combinations of conditions are required to be listed.

6. Corrective action taken by the RAS.
   - For schemes shedding load or generation, the maximum amount of MW should be included.

7. Any additional explanation relevant to high level understanding of the RAS.
   - If deemed necessary, any additional information can be included in this section, but is not mandatory.

Project 2015-06 – Interconnection Reliability Operations and Coordination

Mapping Document | Updated May 2015

This mapping document shows the translation of Requirements in the following currently-enforceable standards to revised standards developed in Project 2015-06:

- IRO-006-EAST-1 —Transmission Loading Relief Procedure for the Eastern Interconnection
- IRO-009-1 — Reliability Coordinator Actions to Operate Within IROLs - Responsibilities and Authorities

Standard IRO-006-EAST-1 — Transmission Loading Relief Procedure for the Eastern Interconnection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's TV, each Reliability Coordinator shall initiate, prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated), one or more of the following actions: • Inter-area redispatch of generation • Intra-area redispatch of generation • Reconfiguration of the transmission system • Voluntary load reductions (e.g., Demand-side Management) • Controlled load reductions (e.g., load shedding)	Standard IRO-006-EAST-2 — Transmission Loading Relief Procedure for the Eastern Interconnection ***Rationale for recommendation to retire Requirement R1:*** *The IRO standard drafting team (IRO SDT) agrees with the FYRT's assertion that IRO-006-EAST-1 Requirement R1 is redundant with IRO-008-1, Requirement R3, and IRO-009-1, Requirement R4, and that the requirements in IRO-008-1 and IRO-009-1 are results based and specify a reliability objective to be achieved. The IRO SDT further agrees with the Five Year Review Team's (FYRT) conclusion that IRO-006-EAST-1 Requirement R1 simply provides a list of actions to be taken without any parameters for their use.*
R2. To ensure operating entities are provided with information needed to maintain an awareness of changes to the Transmission System, when initiating the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance, and at least every clock hour (with the exception of TLR-1, where an hourly update is not required) after initiation up to and including the hour when the TLR level has been	Standard IRO-006-EAST-2 — Transmission Loading Relief Procedure for the Eastern Interconnection **R1.** Each Reliability Coordinator that initiates the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance shall identify the TLR level and the congestion management actions to be implemented, and shall update this information at least every clock hour (except TLR-1) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0.[1]

Standard IRO-006-EAST-1 — Transmission Loading Relief Procedure for the Eastern Interconnection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
identified as TLR Level 0, the Reliability Coordinator shall identify: **2.1.** A list of congestion management actions to be implemented, and **2.2.** One of the following TLR levels: TLR-1, TLR-2, TLR-3A, TLR-3B, TLR-4, TLR-5A, TLR-5B, TLR-6, TLR-0	_____ [1] For more information on TLR levels, please see "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document." ***Rationale for revisions to new Requirement R1 (previously Requirement R2):*** *The IRO SDT provided edits to improve clarity and to incorporate and simplify the sub-requirements into the main requirement.*
R3. Upon the identification of the TLR level and a list of congestion management actions to be implemented, the Reliability Coordinator initiating this TLR procedure shall: **3.1.** Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level **3.2.** Communicate the list of congestion management actions to be implemented to 1.) all Reliability Coordinators in the Eastern Interconnection, and 2.) those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions. **3.3.** Request that the congestion management actions identified in Requirement R2, Part 2.1 be implemented by: 1.) Each Reliability Coordinator associated with a Sink Balancing Authority for which Interchange Transactions are to be curtailed,	Standard IRO-006-EAST-2 — Transmission Loading Relief Procedure for the Eastern Interconnection ***Rationale for recommendation to retire Requirement R3:*** *The IRO SDT agrees with the FYRT's determination that the intent of Requirement R3 is not to define a curtailment process when the Interchange Distribution Calculator (IDC) is compromised or unavailable. In the event of an IDC failure, TLR action would be very limited resulting in manual curtailments and other manual actions to preserve the reliability of the Bulk Electric System. The IRO SDT further agrees with the FYRT's assertion that Requirement R3 contains actions that are automatically generated via the IDC tool and sent to proper entities upon issuance of the TLR. This requirement should be removed from the standard, as it meets Paragraph 81 Criterion B1 – Administrative.*[1]

[1] Paragraph 81 Criteria available at: http://www.nerc.com/pa/Stand/Project%20200812%20Coordinate%20Interchange%20Standards%20DL/Paragraph_81_Criteria.pdf.

Standard IRO-006-EAST-1 — Transmission Loading Relief Procedure for the Eastern Interconnection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
2.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is to be curtailed, and 3.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which its Market Flow is to be curtailed.	
R4. Each Reliability Coordinator that receives a request as described in Requirement R3, Part 3.3. shall, within 15 minutes of receiving the request, implement the congestion management actions requested by the issuing Reliability Coordinator as follows: • Instruct its Balancing Authorities to implement the Interchange Transaction schedule change requests. • Instruct its Balancing Authorities to implement the Network Integration Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible. • Instruct its Balancing Authorities to implement the Market Flow schedule changes for which the Balancing Authorities are responsible. • If an assessment determines shows that one or more of the congestion management actions communicated in Requirement R3, Part 3.3 will result in a reliability concern or will be ineffective, the Reliability Coordinator may replace those specific actions with alternate congestion management actions, provided that:	Standard IRO-006-EAST-2 — Transmission Loading Relief Procedure for the Eastern Interconnection **R2.** Each Reliability Coordinator with a Sink Balancing Authority that must implement congestion management actions pursuant to the Eastern Interconnection TLR procedure shall instruct the Sink Balancing Authority to implement the congestion management actions within 15 minutes of receiving the request from the issuing Reliability Coordinator, subject to the following exception: • Should an assessment determine that one or more of the congestion management actions communicated will result in a reliability concern or will be ineffective, the Reliability Coordinator with a Sink Balancing Authority shall coordinate alternate congestion management actions with the issuing Reliability Coordinator. ***Rationale for Revisions to new Requirement R2 (previously Requirement R4):*** *The IRO SDT provided edits to improve clarity and to incorporate and simplify some of the bullets into the main requirement, and modified the remaining bullet to be a requirement instead of a passive statement.*

Standard IRO-006-EAST-1 — Transmission Loading Relief Procedure for the Eastern Interconnection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
• The alternate congestion management actions have been agreed to by the initiating Reliability Coordinator, and • The assessment shows that the alternate congestion management actions will not adversely affect reliability.	

Standard IRO-009-1 — Reliability Coordinator Actions to Operate Within IROLs - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.	Standard IRO-009-2 — Reliability Coordinator Actions to Operate Within IROLs - Responsibilities and Authorities **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding): **1.1** That can be implemented in time to prevent the identified IROL exceedance. **1.2** To mitigate the magnitude and duration of an IROL exceedance such that the IROL is relieved within the IROL's Tv.
R2. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv.	Standard IRO-009-2 — Reliability Coordinator Actions to Operate Within IROLs - Responsibilities and Authorities ***Rationale for revisions to this Requirement (previously Requirement R2):*** *The IRO SDT revised this requirement by combining IRO-009-1 Requirements R1 and R2 to form one requirement, Requirement R1, with two subparts to make the requirements more concise, as both requirements contained similar language.*
R3. When an assessment of actual or expected system conditions predicts that an IROL in its Reliability Coordinator Area will be exceeded, the Reliability Coordinator shall implement one or more Operating Processes, Procedures or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirements R1) to prevent exceeding that IROL.	Standard IRO-009-2 — Reliability Coordinator Actions to Operate Within IROLs - Responsibilities and Authorities **R2.** Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. ***Rationale for revisions to new Requirement R2 (previously Requirement R3):*** *The IRO SDT revised the language of this requirement to improve clarity as well as consistency with similar*

Standard IRO-009-1 — Reliability Coordinator Actions to Operate Within IROLs - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	NERC Board of Trustees (Board) approved standards, such as, TOP standard revisions (TOP-001-3 R14); "IROL exceedance," "Real Time monitoring," and "Real Time Assessments."
R4. When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv.	Standard IRO-009-2 — Reliability Coordinator Actions to Operate Within IROLs - Responsibilities and Authorities **R3.** Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. ***Rationale for Revisions to Requirement R3 (previously Requirement R4):*** *The IRO SDT removed the term "without delay" from the requirement upon determining that the point of time at which the requirement is triggered is inherent in the requirement itself. The IRO SDT also revised the language of this requirement to improve clarity as well as consistency with similar Board approved standards, such as, TOP standard revisions (TOP-001-3 R14); "IROL exceedance," "Real Time monitoring," and "Real Time Assessments."*
R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.	Standard IRO-009-2 — Reliability Coordinator Actions to Operate Within IROLs - Responsibilities and Authorities **R4.** Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in an IROL or its Tv between Reliability Coordinators that are responsible for that Facility (or group of Facilities). ***Rationale for revisions to Requirement R4 (previously Requirement R5):*** *The IRO SDT revised the language of this requirement for clarity as well as consistency with similar Board approved standards, such as TOP standard revisions (TOP-001-3 R18). The IRO SDT retained clarifying language to limit applicability to appropriate affected RCs.*

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-06 Interconnection Reliability Operations and Coordination
IRO-006-EAST-2

Standards Involved

Approval:

- IRO-006-EAST-2 – Transmission Loading Relief Procedure for the Eastern Interconnection

Retirement:

- IRO-006-EAST-1 – Transmission Loading Relief Procedure for the Eastern Interconnection

Prerequisite Approvals

N/A

Background

Project 2015-06 Interconnection Reliability Operations and Coordination (Project) was initiated to implement the Project 2012-09 Interconnection Reliability Operations Five-Year Review Team (FYRT) recommendations to revise IRO-006-EAST-1 and IRO-009-1.

The FYRT originally reviewed IRO-003-2, IRO-004-2, IRO-005-4, IRO-006-5, IRO-006-East, IRO-008-1, IRO-009-1 and IRO-010-1a, and recommended revising all of these standards except for IRO-006-5, which was reaffirmed by the NERC Board of Trustees (Board). Additionally, Project 2014-03 Revisions to TOP and IRO Standards, retired IRO-003-2, IRO-004-2, IRO-005-4, IRO-008-1, and IRO-010-1a, leaving only IRO-006-EAST-1 and IRO-009-1 with outstanding recommendations for revision.

Based on the FYRT's recommendation to revise IRO-006-EAST-1 and industry comments in response to the 30-day informal comment period for the Project ending on April 15, 2015, the Project standard drafting team (SDT) recommends revising the standard as reflected in the posted documents.

General Considerations

Reliability Standard IRO-006-EAST-2 is proposed for approval to address the recommendations of the five-year review and industry comments.

Effective Date

Reliability Standard IRO-006-EAST-2 shall become effective on the first day of the second calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is

required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards

Reliability Standard IRO-006-EAST-1 shall be retired at midnight of the day immediately prior to the effective date of IRO-006-EAST-2 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Reliability Standard IRO-006-EAST-1 will continue to be implemented pursuant to the Implementation Plan for IRO-006-EAST-1 and is incorporated herein by reference.

Cross References

The Implementation Plan for IRO-006-EAST-1 is available here.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This version of Reliability Standard IRO-006-EAST is posted for a 45-day concurrent comment and ballot period to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team. That review resulted in a recommended drafting effort, which is being conducted by the Project 2015-06 Interconnection Reliability Operations and Coordination standard drafting team.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 11, 2015
SAR posted for comment	March 16 – April 15, 2015

Anticipated Actions	Anticipated Dates
45-day formal or informal comment period with ballot	May – July 2015
Final ballot	July 2015
NERC Board (Board) adoption	November 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None.

The rationale boxes will be moved to the Supplemental Material Section of the standard after the standard is adopted by the NERC Board of Trustees.

A. Introduction

1. **Title: Transmission Loading Relief Procedure for the Eastern Interconnection**
2. **Number:** IRO-006-EAST-~~1~~2
3. **Purpose:** To ensure coordinated action between Reliability Coordinators within the Eastern ~~provide an~~ Interconnection~~-wide~~ when implementing transmission loading relief procedures (TLR) for the Eastern Interconnection ~~that can be used~~ to prevent ~~and/~~or ~~mitigate~~ manage potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1.** Reliability Coordinators in the Eastern Interconnection.
5. **Proposed Effective Date:** See the Implementation Plan for IRO-006-EAST-2.~~First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.~~

B. Requirements

Rationale for recommendation to retire Requirement R1: The standard drafting team (IRO SDT) agrees with the FYRT's assertion that IRO-006-EAST-1 Requirement R1 is redundant with IRO-008-1, Requirement R3, and IRO-009-1, Requirement R4, and that the requirements in IRO-008-1 and IRO-009-1 are results based and specify a reliability objective to be achieved. The IRO SDT further agrees with the FYRT's conclusion that IRO-006-EAST-1 Requirement R1 simply provides a list of actions to be taken without any parameters for their use.

~~**R1.** When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's TV, each Reliability Coordinator shall initiate, prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated), one or more of the following actions: [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]~~

- ~~Inter-area redispatch of generation~~
- ~~Intra-area redispatch of generation~~
- ~~Reconfiguration of the transmission system~~
- ~~Voluntary load reductions (e.g., Demand-side Management)~~

- ~~Controlled load reductions (e.g., load shedding)~~

Rationale for revisions to new Requirement R1 (previously Requirement R2): The IRO SDT provided edits to improve clarity and to incorporate and simplify the sub-requirements into the main requirement.

R1~~2~~. Each Reliability Coordinator that initiates~~To ensure operating entities are provided with information needed to maintain an awareness of changes to the Transmission System, when initiating~~ the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance~~,~~ shall identify the TLR level and the congestion management actions to be implemented, and shall update this information at least every clock hour (~~with the~~ except~~ion of~~ TLR-1~~, where an hourly update is not required~~) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0.[1]~~, the Reliability Coordinator shall identify:~~ [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

~~**2.1.** A list of congestion management actions to be implemented, and~~

~~One of the following TLR levels: TLR-1, TLR-2, TLR-3A, TLR-3B, TLR-4, TLR-5A, TLR-5B, TLR-6, TLR-0~~[1]

~~[1] For more information on TLR levels, please see "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document."~~

[1] For more information on TLR levels, please see "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document."

Rationale for recommendation to retire Requirement R3: The IRO SDT agrees with the FYRT's determination that the intent of Requirement R3 is not to define a curtailment process when the IDC is compromised or unavailable. In the event of an IDC failure, TLR action would be very limited resulting in manual curtailments and other manual actions to preserve the reliability of the Bulk Electric System. The IRO SDT further agrees with the FYRT's assertion that Requirement R3 contains actions that are automatically generated via the IDC tool and sent to proper entities upon issuance of the TLR. This requirement should be removed from the standard, as it meets Paragraph 81 Criterion B1 – Administrative.

~~**R3.** Upon the identification of the TLR level and a list of congestion management actions to be implemented, the Reliability Coordinator initiating this TLR procedure shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]~~

~~**3.1.** Notify all Reliability Coordinators in the Eastern Interconnection of the identified TLR level~~

~~**3.2.** Communicate the list of congestion management actions to be implemented to 1.) all Reliability Coordinators in the Eastern Interconnection, and 2.) those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions.~~

~~**3.3.** Request that the congestion management actions identified in Requirement R2, Part 2.1 be implemented by:~~

~~1.) Each Reliability Coordinator associated with a Sink Balancing Authority for which Interchange Transactions are to be curtailed,~~

~~2.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which Network Integration Transmission Service or Native Load is to be curtailed, and~~

~~3.) Each Reliability Coordinator associated with a Balancing Authority in the Eastern Interconnection for which its Market Flow is to be curtailed.~~

Rationale for Revisions to new Requirement R2 (previously Requirement R4): The IRO SDT provided edits to improve clarity and to incorporate and simplify some of the bullets into the main requirement, and modified the remaining bullet to be a requirement instead of a passive statement.

R4~~2~~. Each Reliability Coordinator with a Sink Balancing Authority that must implement congestion management actions pursuant to the Eastern

Interconnection TLR procedure ~~that receives a request as described in Requirement R3, Part 3.3.~~ shall instruct the Sink Balancing Authority to implement the congestion management actions~~,~~ within 15 minutes of receiving the request~~, implement the congestion management actions requested by~~from the issuing Reliability Coordinator, subject to the following exception: ~~as follows:~~ [*Violation Risk Factor: High*] [~~*Time Horizon: Real-time Operations*~~]

- ~~Instruct its Balancing Authorities to implement the Interchange Transaction schedule change requests.~~
- ~~Instruct its Balancing Authorities to implement the Network Integration Transmission Service and Native Load schedule changes for which the Balancing Authorities are responsible.~~
- ~~Instruct its Balancing Authorities to implement the Market Flow schedule changes for which the Balancing Authorities are responsible.~~
- Should ~~If~~ an assessment determine~~s shows~~ that one or more of the congestion management actions communicated ~~in Requirement R3, Part 3.3~~ will result in a reliability concern or will be ineffective, the Reliability Coordinator with a Sink Balancing Authority shall coordinate alternate congestion management actions with the issuing Reliability Coordinator ~~the Reliability Coordinator may replace those specific actions with alternate congestion management actions, provided that:~~.

  ~~The alternate congestion management actions have been agreed to by the initiating Reliability Coordinator, and~~

  ~~The assessment shows that the alternate congestion management actions will not adversely affect reliability.~~

~~Measures~~

~~C. M1. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that when acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's Tv, the Reliability Coordinator initiated one or more of the actions listed in R1 prior to or concurrently with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated)(R1).~~

M21. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level and a list of congestion management actions to be implemented in accordance with Requirement R1~~(R2)~~.

~~**M3.** Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that after it identified a TLR level and a list of congestion management actions to take, it 1.) notified all Reliability Coordinators in the Eastern Interconnection of the TLR Level, 2.) communicated the list of actions to all Reliability Coordinators in the Eastern Interconnection and those Reliability Coordinators in other Interconnections responsible for curtailing Interchange Transactions crossing Interconnection boundaries identified in the list of congestion management actions, and 3.) requested the Reliability Coordinators identified in Requirement R3 Part 3.2 to implement the congestion management actions identified in Requirement R2 Part 2.1 (R3).~~

M42.~~.~~ Each Reliability Coordinator with a Sink Balancing Authority that must implement congestion management actions pursuant to the Eastern Interconnection TLR procedure shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that within fifteen minutes of the receipt of a request ~~as described in R3~~, the Reliability Coordinator complied with the request by either 1~~.~~) instructing the Sink Balancing Authority to implement the congestion management actions~~implementing the communicated congestion management actions~~ requested by the issuing Reliability Coordinator, or 2~~.~~) implementing none or some of the communicated congestion management actions requested by the issuing Reliability Coordinator, and replacing the remainder with alternate congestion management actions if assessment showed that some or all of the requested congestion management actions ~~communicated in R3~~ would have resulted in a reliability concern or would have been ineffective~~., the alternate congestion management actions were agreed to by the initiating Reliability Coordinator,, and assessment showed that the alternate congestion management actions would not adversely affect reliability~~ in accordance with Requirement R2~~(R4)~~.

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1 and Requirement R2, the Reliability Coordinator shall maintain evidence to show compliance with Requirement R1 and Requirement R2 for the past 12 months plus the current month.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

None.

~~**1.1. Compliance Enforcement Authority**~~

~~Regional Entity.~~

~~**1.2. Compliance Monitoring and Enforcement**~~

~~Processes: The following processes may be used:~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~**1.3.** Data Retention~~

~~The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

~~The Reliability Coordinator shall maintain evidence to show compliance with R1, R2, R3, and R4 for the past 12 months plus the current month.~~

~~If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

~~**1.4.** Additional Compliance Information~~

~~None.~~

3. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				When acting or instructing others to act to mitigate the magnitude and duration of the instance of exceeding an IROL within that IROL's T_V, the Reliability Coordinator did not initiate one or more of the actions listed under R1 prior to or in conjunction with the initiation of the Eastern Interconnection TLR procedure (or continuing management of this procedure if already initiated).

R~~2~~1	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R42				The responding Reliability Coordinator did not, within 15 minutes of receiving a request, either 1.) instruct the Sink Balancing Authority to implement all the requested congestion management actions, or 2.) implement none or some of the requested congestion management actions and replace the remainder with coordinate alternate

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				congestion management actions with the issuing Reliability Coordinator, provided that: assessment showed that the actions replaced would have resulted in a reliability concern or would have been ineffective.~~, the alternate congestion management actions were agreed to by the initiating Reliability Coordinator, and assessment determined that the alternate congestion management actions would not adversely affect reliability.~~

E. Variances

None.

F. Associated Documents

Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document

G. Revision Version History

Version	Date	Action	Tracking
1		Creation of new standard, incorporating concepts from IRO-006-4 Attachment; elimination of Regional Differences, as the standard allows the use of Market Flow	New
1		Adopted by NERC Board of Trustees	November 4, 2010
2			Revised to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team.
1	April 21, 2011	FERC Order issued approving IRO-006-EAST-1 (approval effective June 27, 2011)	

Standard Attachments

Implementation Guideline for Reliability Coordinators:
Eastern Interconnection TLR Levels

The listed system conditions examples are intended to assist the Reliability Coordinator in determining what level of TLR to call. The Reliability Coordinator has the discretion to choose any of these levels regardless of the examples listed, provided the Reliability Coordinator has reliability reasons to take such action. TLR levels are neither required nor expected to be issued in numerical order of level.

Table 1: Eastern Interconnection TLR Levels

Level	Examples of Possible System Conditions
TLR-1	• At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.
TLR-2	• At least one Transmission Facility is approaching or is at its SOL or IROL. o Analysis shows that holding new and increasing non-firm Interchange Transactions and energy flows for the next hour can prevent exceeding this SOL or IROL.
TLR-3a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. o Analysis shows that full or partial curtailment or reallocation[2] of non- firm Interchange Transactions and energy flows can prevent exceeding this SOL and IROL.
TLR-3b	• At least one Transmission Facility is exceeding its SOL or IROL; or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. o Analysis shows that full or partial curtailment or reallocation[2] of non- firm Interchange Transactions and energy flows can prevent exceeding this SOL or IROLs.
TLR-4	• At least one Transmission Facility is expected to exceed its SOL or IROL. o Analysis shows that full curtailment of non-firm Interchange Transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.
TLR-5a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. o Analysis shows that the following actions can prevent exceeding the SOL or IROL: ▪ Full curtailment non-firm Interchange Transactions and energy flows, and ▪ Reconfiguration of the transmission system, if possible, and ▪ Full or partial curtailment or reallocation[2] of firm Interchange Transactions and energy flows.

[2] "Reallocation" is a term defined within the NAESB TLR standards.

Level	Examples of Possible System Conditions
TLR-5b	• At least one Transmission Facility is exceeding its SOL or IROL; or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. o Analysis shows that the following actions can prevent exceeding the SOL or IROL: ▪ Full curtailment of non-firm Interchange Transactions and energy flows, and ▪ Reconfiguration of the transmission system, if possible; and ▪ Full or partial curtailment or reallocation[2] of firm Interchange Transactions and energy flows.
TLR-6	• At least one Transmission Facility is exceeding its SOL or IROL; or • At least one Transmission Facility is expected to exceed its SOL or IROL upon the removal from service of a generating unit or another transmission facility.
TLR-0	• No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the Interconnection-wide transmission loading relief procedure may be terminated

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard IRO-006-EAST-1 — Transmission Loading Relief Procedure for the Eastern Interconnection

United States

Standard	Requirement	Enforcement Date	Inactive Date
IRO-006-EAST-1	All	07/01/2011	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This version of Reliability Standard IRO-006-EAST is posted for a 45-day concurrent comment and ballot period to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team. That review resulted in a recommended drafting effort, which is being conducted by the Project 2015-06 Project 2015-06 Interconnection Reliability Operations and Coordination standard drafting team.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 11, 2015
SAR posted for comment	March 16 – April 15, 2015

Anticipated Actions	Anticipated Dates
45-day formal or informal comment period with ballot	May – July 2015
Final ballot	July 2015
NERC Board (Board) adoption	November 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None.

The rationale boxes will be moved to the Supplemental Material Section of the standard after the standard is adopted by the NERC Board of Trustees.

A. Introduction

1. **Title:** **Transmission Loading Relief Procedure for the Eastern Interconnection**
2. **Number:** IRO-006-EAST-2
3. **Purpose:** To ensure coordinated action between Reliability Coordinators within the Eastern Interconnection when implementing transmission loading relief procedures (TLR) for the Eastern Interconnection to prevent or manage potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators in the Eastern Interconnection
5. **Effective Date:** See Implementation Plan for IRO-006-EAST-2.

B. Requirements and Measures

Rationale for recommendation to retire Requirement R1: The standard drafting team (IRO SDT) agrees with the FYRT's assertion that IRO-006-EAST-1 Requirement R1 is redundant with IRO-008-1, Requirement R3, and IRO-009-1, Requirement R4, and that the requirements in IRO-008-1 and IRO-009-1 are results based and specify a reliability objective to be achieved. The IRO SDT further agrees with the FYRT's conclusion that IRO-006-EAST-1 Requirement R1 simply provides a list of actions to be taken without any parameters for their use.
Rationale for recommendation to retire Requirement R3: The IRO SDT agrees with the FYRT's determination that the intent of Requirement R3 is not to define a curtailment process when the IDC is compromised or unavailable. In the event of an IDC failure, TLR action would be very limited resulting in manual curtailments and other manual actions to preserve the reliability of the Bulk Electric System. The IRO SDT further agrees with the FYRT's assertion that Requirement R3 contains actions that are automatically generated via the IDC tool and sent to proper entities upon issuance of the TLR. This requirement should be removed from the standard, as it meets Paragraph 81 Criterion B1 – Administrative.

Rationale for revisions to new Requirement R1 (previously Requirement R2): The IRO SDT provided edits to improve clarity and to incorporate and simplify the sub-requirements into the main requirement.

R1. Each Reliability Coordinator that initiates the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance shall identify the TLR level and the congestion management actions to be implemented, and shall update this information at least every clock hour (except TLR-1) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0.[1] [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

M1. Each Reliability Coordinator shall provide evidence (such as dated logs, voice recordings, or other information in electronic or hard-copy format) that at the time it initiated the Eastern Interconnection TLR procedure, and at least every clock hour after initiation up to and including the hour when the TLR level was identified as TLR Level 0, the Reliability Coordinator identified both the TLR Level and a list of congestion management actions to be implemented in accordance with Requirement R1.

Rationale for Revisions to new Requirement R2 (previously Requirement R4): The IRO SDT provided edits to improve clarity and to incorporate and simplify some of the bullets into the main requirement, and modified the remaining bullet to be a requirement instead of a passive statement.

R2. Each Reliability Coordinator with a Sink Balancing Authority that must implement congestion management actions pursuant to the Eastern Interconnection TLR procedure shall instruct the Sink Balancing Authority to implement the congestion management actions within 15 minutes of receiving the request from the issuing Reliability Coordinator, subject to the following exception: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

- Should an assessment determine that one or more of the congestion management actions communicated will result in a reliability concern or will be ineffective, the Reliability Coordinator with a Sink Balancing Authority shall coordinate alternate congestion management actions with the issuing Reliability Coordinator.

M2. Each Reliability Coordinator with a Sink Balancing Authority that must implement congestion management actions pursuant to the Eastern Interconnection TLR procedure shall provide evidence (such as dated logs, voice recordings, or other

[1] For more information on TLR levels, please see "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document."

information in electronic or hard-copy format) that within fifteen minutes of the receipt of a request, the Reliability Coordinator complied with the request by either 1) instructing the Sink Balancing Authority to implement the congestion management actions requested by the issuing Reliability Coordinator, or 2) implementing none or some of the communicated congestion management actions requested by the issuing Reliability Coordinator, and replacing the remainder with alternate congestion management actions if assessment showed that some or all of the requested congestion management actions would have resulted in a reliability concern or would have been ineffective in accordance with Requirement R2.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1 and Requirement R2, the Reliability Coordinator shall maintain evidence to show compliance with Requirement R1 and Requirement R2 for the past 12 months plus the current month.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for one clock hour during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for two clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for three clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.	The Reliability Coordinator initiating the Eastern Interconnection TLR procedure missed identifying the TLR Level and/or a list of congestion management actions to take as specified by the requirement for four or more clock hours during the period from initiation up to the hour when the TLR level was identified as TLR Level 0.
R2.				The responding Reliability Coordinator did not, within 15 minutes of receiving a request, either 1) instruct the Sink Balancing Authority to implement all the requested congestion management actions, or 2) coordinate alternate congestion management actions with the issuing Reliability Coordinator,

				provided that: assessment showed that the actions replaced would have resulted in a reliability concern or would have been ineffective.

D. Regional Variances

None.

E. Associated Documents

Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels Reference Document

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	November 4, 2010
2			Revised to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team.

Standard Attachments

Implementation Guideline for Reliability Coordinators:
Eastern Interconnection TLR Levels

The listed system conditions examples are intended to assist the Reliability Coordinator in determining what level of TLR to call. The Reliability Coordinator has the discretion to choose any of these levels regardless of the examples listed, provided the Reliability Coordinator has reliability reasons to take such action. TLR levels are neither required nor expected to be issued in numerical order of level.

Table 1: Eastern Interconnection TLR Levels

Level	Examples of Possible System Conditions
TLR-1	• At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.
TLR-2	• At least one Transmission Facility is approaching or is at its SOL or IROL. o Analysis shows that holding new and increasing non-firm Interchange Transactions and energy flows for the next hour can prevent exceeding this SOL or IROL.
TLR-3a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. o Analysis shows that full or partial curtailment or reallocation[2] of non- firm Interchange Transactions and energy flows can prevent exceeding this SOL and IROL.
TLR-3b	• At least one Transmission Facility is exceeding its SOL or IROL; or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. o Analysis shows that full or partial curtailment or reallocation[2] of non- firm Interchange Transactions and energy flows can prevent exceeding this SOL or IROLs.
TLR-4	• At least one Transmission Facility is expected to exceed its SOL or IROL. o Analysis shows that full curtailment of non-firm Interchange Transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.
TLR-5a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. o Analysis shows that the following actions can prevent exceeding the SOL or IROL: ▪ Full curtailment non-firm Interchange Transactions and energy flows, and ▪ Reconfiguration of the transmission system, if possible, and

[2] "Reallocation" is a term defined within the NAESB TLR standards.

	▪ Full or partial curtailment or reallocation[2] of firm Interchange Transactions and energy flows.

Level	Examples of Possible System Conditions
TLR-5b	• At least one Transmission Facility is exceeding its SOL or IROL; or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. o Analysis shows that the following actions can prevent exceeding the SOL or IROL: ▪ Full curtailment of non-firm Interchange Transactions and energy flows, and ▪ Reconfiguration of the transmission system, if possible; and ▪ Full or partial curtailment or reallocation[2] of firm Interchange Transactions and energy flows.
TLR-6	• At least one Transmission Facility is exceeding its SOL or IROL; or • At least one Transmission Facility is expected to exceed its SOL or IROL upon the removal from service of a generating unit or another transmission facility.
TLR-0	• No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the Interconnection-wide transmission loading relief procedure may be terminated

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-06 Interconnection Reliability Operations and Coordination
IRO-009-2

Standards Involved

Approval:

- IRO-009-2 – Reliability Coordinator Actions to Operate within IROLs

Retirement:

- IRO-009-1 – Reliability Coordinator Actions to Operate within IROLs

Prerequisite Approvals

N/A

Background

Project 2015-06 Interconnection Reliability Operations and Coordination (Project) was initiated to implement the Project 2012-09 Interconnection Reliability Operations Five-Year Review Team (FYRT) recommendations to revise IRO-006-EAST-1 and IRO-009-1.

The FYRT originally reviewed IRO-003-2, IRO-004-2, IRO-005-4, IRO-006-5, IRO-006-East, IRO-008-1, IRO-009-1 and IRO-010-1a, and recommended revising all of these standards except for IRO-006-5, which was reaffirmed by the NERC Board of Trustees (Board). Additionally, Project 2014-03 Revisions to TOP and IRO Standards, retired IRO-003-2, IRO-004-2, IRO-005-4, IRO-008-1, and IRO-010-1a, leaving only IRO-006-EAST-1 and IRO-009-1 with outstanding recommendations for revision.

Based on the FYRT's recommendation to revise IRO-009-1 and industry comments in response to the 30-day informal comment period for the Project ending on April 15, 2015 the Project standard drafting team (SDT) recommends revising the standard as reflected in the posted documents.

General Considerations

Reliability Standard IRO-009-2 is proposed for approval to address the recommendations of the five-year review and industry comments.

Effective Date

Reliability Standard IRO-009-2 shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a

standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards

Reliability Standard IRO-009-1 shall be retired at midnight of the day immediately prior to the effective date of IRO-009-2 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Reliability Standard IRO-009-1 will continue to be implemented pursuant to the Implementation Plan for IRO-009-1 and is incorporated herein by reference.

Cross References

The Implementation Plan for IRO-009-1 is available here.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This version of Reliability Standard IRO-009 is posted for a 45-day concurrent comment and ballot period to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team. That review resulted in a recommended drafting effort, which is being conducted by the Project 2015-06 Interconnection Reliability Operations and Coordination standard drafting team.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 11, 2015
SAR posted for comment	March 16 – April 15, 2015

Anticipated Actions	Anticipated Dates
45-day formal or informal comment period with ballot	May – July 2015
Final ballot	July 2015
NERC Board of Trustees (Board) adoption	November 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None.

The rationale boxes will be moved to the Supplemental Material Section of the standard after the standard is adopted by the Board.

A. Introduction

1. **Title:** **Reliability Coordinator Actions to Operate Within IROLs**
2. **Number:** IRO-009-2
3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator.

5. **Effective Date:** See the Implementation Plan for IRO-009-2.

B. Requirements and Measures

Rationale for revisions to Requirement R1: The standard drafting team (IRO SDT) revised this requirement by combining IRO-009-1 Requirements R1 and R2 to form one requirement with two subparts to make the requirements more concise, as both requirements contained similar language.

R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning or Same Day Operations]*

1.1 That can be implemented in time to prevent the identified IROL exceedance.

1.2 To mitigate the magnitude and duration of an IROL exceedance such that the IROL is relieved within the IROL's T_V.

M1. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it has Operating Processes, Procedures, or Plans to address both preventing and mitigating the magnitude and duration of IROL exceedances in accordance with Requirement R1. This evidence shall include a list of any IROLs (and each associated Tv) identified in advance, along with one or more dated Operating Processes, Procedures, or Plans that that will be used.

Rationale for revisions to new Requirement R2 (previously Requirement R3): The IRO SDT revised the language of this requirement to improve clarity as well as consistency with similar NERC Board of Trustees (Board) approved standards, such as, TOP standard revisions (TOP-001-3 R14); "IROL exceedance," "Real Time monitoring," and "Real Time Assessments."

R2. Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M2. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it initiated one or more Operating Processes, Procedures or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirements R1) in accordance with Requirement R2. This evidence could include, but is not limited to, Operating Processes, Procedures, or Plans from Requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.

Rationale for Revisions to Requirement R3 (previously Requirement R4): The IRO SDT removed the term "without delay" from the requirement upon determining that the point of time at which the requirement is triggered is inherent in the requirement itself. The IRO SDT also revised the language of this requirement to improve clarity as well as consistency with similar Board approved standards, such as, TOP standard revisions (TOP-001-3 R14); "IROL exceedance," "Real Time monitoring," and "Real Time Assessments."

R3. Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M3. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it acted or directed others to act in accordance with Requirement R3. This evidence could include, but is not limited to, Operating Processes, Procedures, or Plans from Requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.

Rationale for revisions to Requirement R4 (previously Requirement R5): The IRO SDT revised the language of this requirement for clarity as well as consistency with similar

Board approved standards, such as TOP standard revisions (TOP-001-3 R18). The IRO SDT retained clarifying language to limit applicability to appropriate affected RCs.

R4. Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in an IROL or its Tv between Reliability Coordinators that are responsible for that Facility (or group of Facilities). *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it operated to the most limiting IROL and Tv in instances where there was a difference in an IROL or its Tv. Such evidence could include, but is not limited to, dated computer printouts, dated operator logs, dated voice recordings, dated transcripts of voice recordings, or other equivalent evidence in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of Requirement R1; Requirement R2; Requirement R3; and Requirement R4 for a rolling 12 months.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records, and all IROL Violation Reports submitted since the last audit.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Exception Reporting: For each instance of exceeding an IROL for time greater than IROL Tv, the Reliability Coordinator shall submit an IROL Violation Report to its Compliance Enforcement Authority within 30 days of the initiation of the event.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.				An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to prevent that IROL exceedance (Part 1.1). OR An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to mitigate that IROL exceedance within the IROL's T_V. (Part 1.2).
R2.				No Operating Processes, Procedures, or Plans were

				initiated that were intended to prevent a predicted IROL exceedance as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment.
R3.				Actual system conditions showed that there was an IROL exceedance in its Reliability Coordinator Area, and that the IROL exceedance was not mitigated within the IROL's Tv.
R4.				The most limiting IROL or its Tv was not operated to between Reliability Coordinators that are responsible for the Facility (or group of Facilities) associated with the IROL.

D. Regional Variances

None.

E. Associated Documents

IROL Violation Report

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
2			Revised to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team.

Standard Attachments

None.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This version of Reliability Standard IRO-009 is posted for a 45-day concurrent comment and ballot period to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team. That review resulted in a recommended drafting effort, which is being conducted by the Project 2015-06 Interconnection Reliability Operations and Coordination standard drafting team.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 11, 2015
SAR posted for comment	March 16 – April 15, 2015

Anticipated Actions	Anticipated Dates
45-day formal or informal comment period with ballot	May – July 2015
Final ballot	July 2015
NERC Board of Trustees (Board) adoption	November 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): **None.**

The rationale boxes will be moved to the Supplemental Material Section of the standard after the standard is adopted by the Board.

A. Introduction

1. **Title:** **Reliability Coordinator Actions to Operate Within IROLs**

2. **Number:** IRO-009-~~1~~2

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).

4. **Applicability:**

   4.1. Reliability Coordinator.

5. ~~**Proposed**~~ **Effective Date:**
   ~~In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.~~

   ~~In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.~~See the Implementation Plan for IRO-009-2.

B. Requirements

Rationale for revisions to Requirements R1: The standard drafting team (IRO SDT) revised this requirement by combining IRO-009-1 Requirements R1 and R2 to form one requirement with two subparts to make the requirements more concise, as both requirements contained similar language.

R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions ~~it~~ the Reliability Coordinator shall take or actions ~~it~~ the Reliability Coordinator shall direct others to take (up to and including load shedding): ~~that can be implemented in time to prevent exceeding those IROLs.~~ *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning or Same Day Operations)*

~~1.1~~ That can be implemented in time to prevent the identified IROL exceedance.

1.1

1.2 ~~**R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) t~~To mitigate the magnitude and duration of ~~exceeding an~~that ~~IROL~~ IROL exceedance such that the IROL is relieved within the IROL's

Tv. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning or Same Day Operations)*

Rationale for revisions to new Requirement R2 (previously Requirement R3): The IRO SDT revised the language of this requirement to improve clarity as well as consistency with similar NERC Board of Trustees (Board) approved standards, such as, TOP standard revisions (TOP-001-3 R14); "IROL exceedance," "Real Time monitoring," and "Real Time Assessments."

R23. When an assessment of actual or expected system conditions predicts that an IROL in its Reliability Coordinator Area will be exceeded, the Each Reliability Coordinator shall implement initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirements R1) that are intended to prevent exceeding that an IROL exceedance as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment.. *(Violation Risk Factor: High) (Time Horizon: Real-time – Operations)*

Rationale for revisions to new Requirement R3 (previously Requirement R4): The IRO SDT removed the term "without delay" from the requirement upon determining that the point of time at which the requirement is triggered is inherent in the requirement itself. The IRO SDT also revised the language of this requirement to improve clarity as well as consistency with similar Board approved standards, such as, TOP standard revisions (TOP-001-3 R14); "IROL exceedance," "Real Time monitoring," and "Real Time Assessments."

R4R3. When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Each Reliability Coordinator shall, without delay, act or direct others to act so that to mitigate the magnitude and duration of the instance of exceeding that an IROL exceedance is mitigated within the IROL's Tv, identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*

Rationale for revisions to Requirement R4 (previously Requirement R5): The IRO SDT revised the language of this requirement for clarity as well as consistency with similar Board approved standards, such as TOP standard revisions (TOP-001-3 R18). The IRO SDT retained clarifying language to limit applicability to appropriate affected RCs.

R45. ~~If unanimity cannot be reached on the value for an IROL or its Tv, e~~Each Reliability Coordinator ~~that monitors that Facility (or group of Facilities)~~ shall operate to~~, without delay, use~~ the most limiting IROL and Tv in instances where there is a difference in an IROL or its Tv between Reliability Coordinators that are responsible for that Facility (or group of Facilities).~~conservative of the values (the value with the least impact on reliability) under consideration.~~ *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*

C. Measures

M1. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it has Operating Processes, Procedures, or Plans to address both preventing and mitigating the magnitude and duration of IROL exceedances ~~instances of exceeding IROLs~~ in accordance with Requirement R1 ~~and Requirement R2~~. This evidence shall include a list of any IROLs (and each associated Tv) identified in advance, along with one or more dated Operating Processes, Procedures, or Plans that that will be used.

M2. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it initiated one or more Operating Processes, Procedures or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirements R1) in accordance with Requirement R2. This evidence could include, but is not limited to, Operating Processes, Procedures, or Plans from Requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.

M3. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it acted or directed others to act in accordance with Requirement R3. This evidence could include, but is not limited to, Operating Processes, Procedures, or Plans from Requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.~~M2. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it acted or directed others to act in accordance with Requirement R3 and Requirement R4. This evidence could include, but is not limited to, Operating Processes, Procedures, or Plans from Requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.~~

M43. ~~For a situation where Reliability Coordinators disagree on the value of an IROL or its Tv, the~~Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it operated to the most limiting IROL and Tv in instances where there was a difference in an IROL or its Tv~~used the most conservative of the values under consideration, without delay.~~ Such evidence could include, but is not limited to, dated computer printouts, dated operator logs, dated voice recordings, dated transcripts of voice recordings, or other equivalent evidence in accordance with Requirement R4. ~~(R5)~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~For Reliability Coordinators that work for the Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.~~

~~For Reliability Coordinators that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.~~

1.1. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of Requirement R1; Requirement R2; Requirement R3; and Requirement for a rolling 12 months.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records, and all IROL Violation Reports submitted since the last audit.

1.2. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.3. Additional Compliance Information

Exception Reporting: For each instance of exceeding an IROL for time greater than IROL Tv, the Reliability Coordinator shall submit an IROL Violation Report to its Compliance Enforcement Authority within 30 days of the initiation of the event.

~~**1.2. Compliance Monitoring Period and Reset Time Frame**~~

~~Not applicable.~~

~~**1.3. Compliance Monitoring and Enforcement Processes**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

Exception Reporting

1.4. Data Retention

The Reliability Coordinator, shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain evidence of Requirement R1, Requirement R2, and Measure M1, for a rolling 12 months.

The Reliability Coordinator shall retain evidence of Requirement R3, Requirement R4, Requirement R5, Measure M2, and Measure M3 for a rolling 12 months.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records, and all IROL Violation Reports submitted since the last audit.

1.5. Additional Compliance Information

Exception Reporting: For each instance of exceeding an IROL for time greater than IROL T_V, the Reliability Coordinator shall submit an IROL Violation Report to its Compliance Enforcement Authority within 30 days of the initiation of the event.

2. Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1				An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to prevent that IROL exceedance (Part 1.1). OR An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to mitigate that IROL exceedance within the IROL's Tv. (Part 1.2)~~An IROL in its Reliability Coordinator Area was identified one or more days in advance and the~~

~~R2~~				~~An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's Tv. (R2)~~
R23				~~An assessment of actual or expected system conditions predicted that an IROL in the Reliability Coordinator's Area would be exceeded, but n~~No Operating Processes, Procedures, or Plans were ~~implemented~~ initiated that were intended to prevent a predicted IROL exceedance as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. ~~(R3)~~

R~~3~~4			~~Actual system conditionsshowed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and there was a delay of five minutes or more before acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding that IROL, however the IROL was mitigated within the IROL Tv.~~	Actual system conditions showed that there was an IROL exceedance in its Reliability Coordinator Area, and that the IROL exceedance was not ~~resolved~~mitigated within the IROL's Tv.

Requirement	Lower	Moderate	High	Severe
			showed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and there was a delay of five minutes or more before acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding that IROL, however the IROL was mitigated within the IROL Tv. (R4)	showed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and that IROL was not resolved within the IROL's Tv. (R4)
R45	Not applicable.	Not applicable.	Not applicable.	The most limiting IROL or its TV was not operated to between Reliability Coordinators that are responsible for the Facility (or group of Facilities) associated with the IROL.There was a disagreement on the value of the IROL or its Tv and the most conservative limit under consideration was not used. (R5)

E. Regional Variances

None

F. Associated Documents

IROL Violation Report

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-009-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VRFs based on June 24, 2013 approval.	
2			Revised to address the recommendations of the Project 2012-09 Interconnected Reliability Operations Five-Year Review Team.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard IRO-009-1 — Reliability Coordinator Actions to Operate Within IROLs

United States

Standard	Requirement	Enforcement Date	Inactive Date
IRO-009-1	All	10/01/2011	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-06 Interconnection Reliability Operations and Coordination
IRO-006-EAST-2, IRO-009-2

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in IRO-006-EAST-2 (Transmission Loading Relief Procedure for the Eastern Interconnection) and IRO-009-2 (Reliability Coordinator Actions to Operate within IROLs).

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Interconnection Reliability Operations and Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to

effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the VRF Level
Guideline 4 was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

Consideration of FERC VRF Guidelines

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

IRO-006-EAST-2

Reliability Standard IRO-006-EAST-2 is a revision of IRO-006-EAST-1 TLR Procedure for the Eastern Interconnection, with the following stated purpose: "To ensure coordinated action between Reliability Coordinators within the Eastern Interconnection when implementing transmission loading relief procedures (TLR) for the Eastern Interconnection to prevent or manage potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES)."

Reliability Standard IRO-006-EAST-2 has two (2) requirements that address identification of TLR level(s) and identification and instruction to implement congestion management actions. The requirements originated from revisions to two (2) requirements that existed in Reliability Standard IRO-006-EAST-1, Requirement R2 and Requirement R4. Reliability Standard IRO-006-EAST-2 seeks to retire two (2) other requirements that existed in IRO-006-EAST-1, Requirement R1 and Requirement R3. As such, the VRFs and VSLs associated with IRO-006-EAST-1, Requirement R1 and Requirement R3 have not been included in IRO-006-EAST-2.

Reliability Standard IRO-006-EAST-2 Requirement R1 maps to IRO-006-EAST-1 Requirement R2, and IRO-006-EAST-2 Requirement R2 maps to IRO-006-EAST-1 Requirement R4. The drafting team did not revise the VRFs for the requirements of IRO-006-EAST-2 Requirement R1 or Requirement R2.

The drafting team revised the VSL for IRO-006-EAST-2 Requirement R2 to conform to the revisions to the language of IRO-006-EAST-2 Requirement R2.

IRO-009-2

Reliability Standard IRO-009-2 is a revision of IRO-009-1 Reliability Coordinator Actions to Operate Within IROLs, with the following stated purpose: To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).

Reliability Standard IRO-009-2 has four (4) requirements that address Reliability Coordinator Operating Process, Procedure, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take to prevent exceeding that IROL, that can be implemented in time to prevent exceeding the identified IROL, mitigate exceeding that IROL within the IROL's Tv, Operating Processes, Procedures or Plans to prevent an IROL exceedance as part of its Real-time monitoring or Real-time Assessment, acts the Reliability Coordinator shall take or direct others to take so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv as part of its Real-time monitoring or Real-time Assessment, and Reliability Coordinator operation to the most limiting IROL and Tv in instances where there is a difference in an IROL or its Tv between Reliability Coordinators that are responsible for a Facility (or group of Facilities). The requirements originated from revisions to the five (5) requirements that existed in IRO-009-1, Requirement R1 through Requirement R5. Reliability Standard IRO-009-2 seeks to revise Requirement R1 and R2 by incorporating the requirements from Requirement R2 into Requirement R1 as Part R1.1 and R1.2.

The IRO-009-2 Requirement R1 maps to IRO-009-1 Requirement R1 and Requirement R2. The VRFs for IRO-009-1 Requirement R1 and Requirement R2 were both medium, therefore, the drafting team did not revise the VRFs for the requirements when revising IRO-009-2 Requirement R1 to include IRO-009-1 Requirement R2.

Reliability Standard IRO-009-2 Requirement R2 maps to IRO-009-1 Requirement R3; IRO-009-2 Requirement R3 maps to IRO-009-1 Requirement R4; IRO-009-2 Requirement R4 maps to IRO-009-1 Requirement R5. The drafting team did not revise the VRFs for the requirements of IRO-006-EAST-1 Requirement R3, Requirement R4, or Requirement R5.

The drafting team revised the VSLs for IRO-009-2 Requirements R2 through R4 to conform to the revisions to the language of IRO-009-2 Requirements R2 through R4.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one (1) VSL. While it is preferable to have four (4) VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one (1), two (2), or three (3) VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on VSLs

In its June 19, 2008 Order[1] on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.
- Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

[1] *Order on Violation Severity levels Proposed by the Electric Reliability Organization*, 123 FERC ¶61,284 (2008)

VRF and VSL Justifications

VRF and VSL Justifications – IRO-006-EAST-2, R2			
Proposed VSL – IRO-006-EAST-2, R2			
Lower	**Moderate**	**High**	**Severe**
			The responding Reliability Coordinator did not, within 15 minutes of receiving a request, either 1) instruct the Sink Balancing Authority to implement all the requested congestion management actions, or 2) coordinate alternate congestion management actions with the issuing Reliability Coordinator, provided that: assessment showed that the actions replaced would have resulted in a reliability concern or would have been ineffective.
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.		
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.		

VRF and VSL Justifications – IRO-006-EAST-2, R2	
Proposed VSL – IRO-006-EAST-2, R2	
VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – IRO-009-2, R1	
Proposed VRF – IRO-009-2, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL and failure to have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's Tv could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from failure to have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL and failure to have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's Tv. Failure to have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL and failure to have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's Tv will not, by themselves, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within the requirement. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – IRO-009-2, R1	
Proposed VRF – IRO-009-2, R1	
	Since the SDT revised the requirement to include a requirement that was already approved along with its associated VRF and VSL, the SDT concludes that there is consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a Medium VRF, which is consistent with the VRF that this requirement and the requirement that was combined with this requirement were previously assigned in the approved standard.

VRF and VSL Justifications – IRO-009-2, R1			
Proposed VRF – IRO-009-2, R1			
Proposed VRF	**Medium**		
FERC VRF G4 Discussion	Failure to have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL and failure to have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's Tv could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from failure to have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL and failure to have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's Tv. Failure to have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL and failure to have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's Tv will not, by themselves, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – IRO-009-2, R1			
Lower	**Moderate**	**High**	**Severe**
			An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to

			prevent exceeding that IROL (Part 1.1). OR An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's Tv. (Part 1.2)

VRF and VSL Justifications – IRO-009-2, R1	
Proposed VSL – IRO-009-2, R1	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – IRO-009-2, R2			
Proposed VSL – IRO-009-2, R2			
Lower	**Moderate**	**High**	**Severe**
			No Operating Processes, Procedures, or Plans were initiated that were intended to prevent a predicted IROL exceedance as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment.
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.		
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.		

VRF and VSL Justifications – IRO-009-2, R3			
Proposed VSL – IRO-009-2, R3			
Lower	**Moderate**	**High**	**Severe**
			Actual system conditions showed that there was an IROL exceedance

VRF and VSL Justifications – IRO-009-2, R3			
Proposed VSL – IRO-009-2, R3			
			in its Reliability Coordinator Area, and that the IROL exceedance was not mitigated within the IROL's Tv.
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.		
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.		

VRF and VSL Justifications – IRO-009-2, R4			
Proposed VSL – IRO-009-2, R4			
Lower	**Moderate**	**High**	**Severe**
			The most limiting IROL or its Tv was not operated to between Reliability Coordinators that are responsible for the Facility (or group of Facilities) associated with the IROL.
FERC VSL G3	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.		

VRF and VSL Justifications – IRO-009-2, R4	
Proposed VSL – IRO-009-2, R4	
VSL Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

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Proposed Revisions to Align Definitions in the Glossary of Terms and Rules of Procedure

Project 2015-04 – Alignment of Terms

Part I. Executive Summary

Currently there are fifty-five (55) defined terms that appear in both the NERC Glossary of Terms Used in Reliability Standards (Glossary) and Rules of Procedure (ROP) ("cross-over terms"), a complete list of which can be found in Attachment 1. Of the fifty-five (55) cross-over terms, forty (40) contain inconsistencies or differences in the definition narratives, which causes industry confusion and may lead to inconsistent interpretation or application of the meaning of a term. Consistency between the defined terms in the Glossary and the ROP will enhance reliability by providing the owners, users and operators of the BES, as well as the ERO Enterprise, with a better understanding of the terminology used in the Glossary and the ROP. To achieve this consistency, the SDT is proposing alignment revisions to twenty-six (26) Glossary terms and sixteen (16) ROP terms.

This document provides an overview of the work undertaken by the Project 2015-04 standard drafting team (SDT) to align the cross-over terms and the revisions proposed by the SDT. Part II provides an overview of the purpose, scope and substance of the work undertaken by the SDT during this project. Parts III through VI provide the background information and research conducted by the SDT for each cross-over term under revision, and an analysis and justification to support the revisions being proposed by the team to align the terms.

Part II. Project Overview and Background Information

Background information regarding the Glossary and ROP

In 2007, when FERC approved Version 0 of the Reliability Standards, it also approved the NERC Glossary of Terms. (*See*, FERC Order No. 693). In Order No. 693, FERC noted the importance of the defined terms in establishing a consistent understanding of the Reliability Standards Requirements and implementation. (*See*, FERC Order No. 693 at P 1893). The NERC Glossary provides continuity in the application of the glossary definitions industry-wide and eliminates multiple interpretations of the same term or function, which could otherwise create miscommunication or jeopardize reliability. Similarly, FERC approved the Rules of Procedure, which contained a number of FERC-approved defined terms. Later, in 2011, at FERC's suggestion, NERC petitioned to move all of the defined terms contained in the various sections and Appendices of the ROP into one central location, Appendix 2 to the ROP. The definitions included in Appendix 2 were "taken largely from existing sources, including Section 215 of the Federal Power Act; the Commission's regulations; the NERC Bylaws, the NERC Glossary of Terms Used in Reliability Standards; and existing definitions found in the ROP and Appendices…" (*See*, NERC Petition, p. 8). Those definitions taken

from the Glossary were marked with a double asterisk (**), while definitions taken from the Federal Power Act were marked with a double plus sign (++).

Following FERC's approval of the Glossary and Appendix 2 to the ROP, there have been a number of necessary revisions to the defined terms contained therein. Glossary terms are revised through the Reliability Standards development process; whereas ROP terms are revised through the ROP revision process. (*See*, NERC Rules of Procedure, Appendix 3A: Standards Process Manual and ROP, Section 1400). As a result of various changes made to defined terms over the years through these distinct revision processes, a number of cross-over terms, which were once identical, now contain differences in their definition narratives. As outlined in the SAR for this project, the purpose of this project is to align the defined terms found in the Glossary and the ROP. Additionally, the SDT will also develop recommendations regarding how to enhance the current definition development processes in the Standards Process Manual and ROP to prevent misalignment or inconsistencies during future development of defined terms.

Work undertaken by the Project 2015-04 SDT

First, the SDT identified all existing defined terms that are contained in both the Glossary and the ROP ("cross-over terms"), a complete list of which can be found in Attachment 1. From this complete list of cross-over terms, the team then identified those cross-over terms that contained definitional differences. After analyzing these definitional differences, the SDT identified common alignment issues and categorized the terms into different "groups" based upon the type of alignment issue identified. Below is a summary of each grouping:

Group 1: Group 1 cross-over terms contain differences in the substance or content of the definition. In some instances, the differences resulted in the defined terms having different meanings or application. For example, the definitions for "Net Energy for Load" are substantively different in the Glossary and ROP because they are used differently in the respective documents. In other instances, although the content or language of the definition was different, the end result or application of the definition was, nevertheless, the same. For example, the term "Adjacent Balancing Authority" is defined differently in the Glossary than the ROP, with the Glossary definition providing greater clarity. There are a total of nine (9) Group 1 cross-over terms, and the SDT is proposing alignment revisions to eight (8) of those terms.

Group 2: Group 2 cross-over terms are similar to Group 1 terms in that the definitions contain substantive differences in the definitions. However, these terms are grouped separately because they are currently under revision, not yet approved by the NERC Board of Trustees, or pending regulatory approval. There are six (6) Group 2 cross-over terms in total, and at this time, the SDT is recommending alignment revisions to one (1) of those terms. The SDT has, however, made recommendations for future action to address a number of the remaining Group 2 cross-over terms.

Group 3: Group 3 cross-over terms contain differences in the capitalization of terms that are included in the definition narrative, but are otherwise aligned in substance and content. Since capitalization of a term indicates that it is a defined term with a specific meaning, these inconsistencies in capitalization cause confusion and may lead to inconsistent application of the definition. For example, the definition narrative of "Interconnected Operations Services" is the same in the Glossary and ROP; however, the ROP

narrative capitalizes “Transmission Services” and “Reliable Operation,” while the Glossary does not. There are a total of twenty-two (22) Group 3 cross-over terms, and the SDT is recommending alignment revisions to all of those terms.

Group 4: Group 4 cross-over terms contain errata-type differences, such as the inadvertent omission of a word or letter. There are three (3) Group 4 cross-over terms in total, and the SDT is proposing alignment revisions to all of those terms.

Below is a detailed summary of the SDT’s recommendations for each of the cross-over terms, organized by Group. Also, Attachment 2 contains a summary of all alignment revisions proposed by the SDT.

The SDT undertook substantial background research before determining whether alignment revisions were appropriate for each of the cross-over terms under consideration, including an examination of the history of the term’s definition, previous drafting teams’ intent, relevant NERC filings to FERC, and any FERC orders approving the term’s definition. Additionally, the SDT examined how each term is used in the Glossary, Reliability Standards, and ROP provisions. Based on this thorough examination, the SDT determined whether revisions were appropriate. In some instances, the SDT concluded that alignment revisions were not appropriate due to differing application of the terms in the Glossary and/or ROP. Also, for a number of terms, the SDT identified areas where the definition language could be improved, given industry usage. For such terms, the SDT will develop a Standards Authorization Request (SAR) outlining the identified issues, and the team’s proposal for how to address each issue. Of the fifty-five (55) cross-over terms, forty (40) contain inconsistencies or differences in the definition narratives. To achieve consistency and alignment of these cross-over terms, the SDT is proposing revisions to twenty-six (26) Glossary terms and sixteen (16) ROP terms.

Part III: Group 1 recommendations

There are a total of nine (9) Group 1 cross-over terms:

Term 1: Adjacent Balancing Authority

Term 6: Bulk Power System

Term 17: Generator Operator

Term 18: Generator Owner

Term 29: Net Energy for Load or NEL

Term 40: Reliability Standard

Term 44: Sink Balancing Authority

Term 45: Source Balancing Authority

Term 48: System Operating Limit

The SDT is recommending revisions to eight (8) of the Group 1 cross-over terms. Below is an overview of the SDT research, assessment, proposed revision(s), and justification for each of the recommendations.

Term 1: Adjacent Balancing Authority

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.	a Balancing Authority Area that is interconnected to another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**	The SDT is proposing to revise the ROP definition to align with the Glossary. Redline of ROP definition: a Balancing Authority ~~Area~~ whose Balancing Authority Area ~~that~~ is interconnected with ~~to~~ another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**

I. HISTORY AND BACKGROUND INFORMATION REGARDING "ADJACENT BALANCING AUTHORITY" DEFINITION

History of Glossary term:

- Previous version(s): Effective dates: 3/16/2007 – 09/30/2014 ("A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.")
- Current version: **Effective as of 10/01/2014**
  - Revised by Project 2008-12 Coordinate Interchange Standards
  - NERC Petition (02/27/2014) - "The proposed revisions are minor, non-substantive changes to improve the clarity of the term, as illustrated in Exhibit F. The proposed revisions are intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange." (p. 29)
  - FERC Order (06/30/2014) – FERC letter order approving revised Glossary definition

History of ROP term:

- Current version: **Effective as of 01/31/2012**
  - NERC Petition (11/29/2011) - Added Appendix 2 to ROP and adopted existing Glossary definition for Adjacent Balancing Authority. (see p. 9)
  - FERC Order (01/31/2012) - "These revisions are being proposed as a result of P 93 of the Commission's Order issued October 21, 2010, in Docket No. RR10-11-000, in which the Commission invited NERC to submit a filing making consistent use of defined terms throughout the ROP and Appendices." (p. 1)

II. USAGE OF DEFINED TERM: ADJACENT BALANCING AUTHORITY

List of usage of the term Adjacent Balancing Authority within Reliability Standards:

	Reliability Standard
1	BAL-001-2
2	BAL-002-1a
3	BAL-005-0.2
4	BAL-006-2
5	COM-001-2
6	EOP-001-2.1b

7	INT-009-2.1
8	MOD-028-2
9	MOD-030-2
10	MOD-030-3

List of ROP provisions (other than Appendix 2) where Adjacent Balancing Authority occurs:

	ROP provision	Page # [Link to ROP]
1	Appendix 5B – Functional type definition under Section II: Reserve Sharing Group	435 of 483

List defined terms that include Adjacent Balancing Authority in definition narrative:

	Glossary
1	Net Actual Interchange
2	Net Interchange Schedule
3	Reserve Sharing Group

	ROP
1	N/A
2	N/A
3	Reserve Sharing Group

List of other defined terms that are included in the Adjacent Balancing Authority definition narrative:

Glossary: Balancing Authority Area, Balancing Authority
ROP: Balancing Authority Area

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: The differences in definition narratives are minor and non-substantive in nature. The Glossary definition clarifies the various Balancing Authorities involved in the implementation of the Interchange and their respective relationships with Interchange.

How/why the terms may be applied differently as a result of the differences: The language added through the Project 2008-12 Coordinate Interchange Standards did not impact the definitions. A review of the ROP and Reliability Standards containing the defined term was conducted, and the differences do not result in different application of the term. The Glossary definition simply provides greater clarity.

Proposed revision(s): The SDT proposes to revise the ROP definition to align with the Glossary. No changes are proposed to the Glossary definition.

Redline of ROP definition:

a Balancing Authority ~~Area~~ whose Balancing Authority Area ~~that~~ is interconnected with ~~to~~ another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**

Justification for decision: The ROP definition adopted the Glossary definition when Appendix 2 was created in 2012. Note that the ROP definition is marked with a double asterisk (**), indicating it was taken from the Glossary. Subsequently, in 2014, the Glossary term was revised to provide greater clarity. The revised Glossary definition clarifies the various Balancing Authorities involved in the implementation of Interchange and their relationships with regard to Interchange. The ROP definition was not updated to reflect the clarifying revisions made to the Glossary definition.

Term 6: Bulk Power System

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
Bulk-Power System: A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.	Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.	The SDT is proposing to revise both definitions as follows: Redline of Glossary definition: Bulk- Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.) Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning. Redline of ROP, Appendix 2 definition: Bulk Power System" means, depending on the context: (i) (A) ~~Facilities~~ facilities and control systems necessary for operating an interconnected electric energy ~~supply and~~ transmission network (or any portion thereof);~~,~~ and (B) electric energy from generation~~g~~ facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. [++] (In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.)~~-~~Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.

I. HISTORY AND BACKGROUND INFORMATION REGARDING BULK POWER SYSTEM DEFINITION

History of Glossary term:

- Original version: Effective through 07/08/13
  - FERC Order No. 693 (03/16/07): "The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the statutory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary." (P 1894)

- Current version: **Effective as of 07/09/13**
  - Revised by Project 2012-08.1 Phase 1 of the Glossary Updates for Statutory Definitions
  - NERC Petition (05/10/13):

    "The term "Bulk-Power System" is defined in section 215 of the FPA as follows:

    (1) The term 'bulk-power system' means—

    (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and

    (B) electric energy from generation facilities needed to maintain transmission system reliability.

    The term does not include facilities used in the local distribution of electric energy.

    The proposed definition of the term "Bulk-Power System" for inclusion in the NERC Glossary is as follows: "Bulk-Power System" means, (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. The proposed definition of "Bulk-Power System" is identical to the definition in section 215 of the FPA and should therefore be accepted in compliance with the Commission's directive in Order No. 693." (pp. 5-6)
  - FERC Order (07/9/13) - Letter order approving proposed definitions

History of ROP term:

- Original version:
  - ERO Application (04/04/06) – NERC Bylaws: "Bulk power system" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and electric energy from generation facilities needed to maintain transmission system reliability, but does not include facilities used in the local distribution of electricity.
  - FERC Order (07/20/06) - 'We direct NERC to adopt definitions of the terms defined in Order No. 672 throughout its documents in its compliance filing. Any other definition of those terms is not acceptable.' (P 727)

- Revised version:
  - NERC Compliance Filing Addressing Governance Issues (09/18/2006): "NERC has modified the definitions of 'bulk power system', 'electric reliability organization', and 'regional entity' in Article I, Section 1 of the Bylaws to track the definitions in Order No. 672. NERC will also track the Order No. 672 definitions in its Rules of Procedure…"
  - NERC Non-Governance Compliance Filing (10/18/06): "NERC has modified the definitions of 'bulk power system', 'electric reliability organization', and 'regional entity' in Article I, Section 1 of its Bylaws to track the definitions in Order No. 672. NERC has also revised definitions in its Rules of Procedure to match definitions in Section 215(a) of the Federal Power Act and/or Part 39 of the Commission's regulations, including 'bulk power system', 'electric reliability organization,' 'reliable operation,' and 'reliability standard'." (pp. 71-72)

    "Bulk power system" means facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system

reliability. The term does not include facilities used in the local distribution of electric energy. (Attachment 1, Revised ROP, at Section 202 Specific Definitions)

- FERC Order Accepting Governance Compliance Filing (10/30/06): "NERC has modified the definitions of 'Bulk-Power System,' 'Electric Reliability Organization,' and 'Regional Entity' in article I, section 1 of the Bylaws to track the definitions in Order No. 672. NERC states that it also intends to incorporate Order No. 672 definitions in its Rules of Procedure." (P 125)
- FERC Order Accepting Non-Governance Compliance Filing (01/18/07): "NERC has appropriately revised definitions in its Bylaws and its Rules of Procedure to reflect these same definitions in Order No. 672." (P 223)

- Current version: **Effective as of 01/31/2012**
  - NERC Petition to Revise ROP (11/29/11): "The purposes of the proposed revisions are (1) to place all definitions of defined terms used anywhere in the ROP in a single, readily-accessible location (proposed new Appendix 2); (2) to capitalize defined terms throughout the ROP where such terms are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the ROP but are not defined terms." (p. 1)
  - FERC Order Approving Amendments to the ROP (01/31/2012): "Pursuant to section 215(f) of the FPA and section 39.10(a) of the Commission's regulations, we approve the proposed revisions to the NERC Rules of Procedure. We agree with NERC that the revisions do not substantively change any original definitions in the Rules of Procedure; moreover, the Rules of Procedure remains procedurally and substantively the same. In addition, the creation of Appendix 2 offers a central, readily-accessible document containing all defined terms as used within the Rules of Procedure." (P 10)

II. USAGE OF DEFINED TERM: BULK POWER SYSTEM

List of usage of the term Bulk-Power System within Reliability Standards:

	Reliability Standard	Location
1	FAC-003-3	Background and Enforcement sections
2	IRO-004-2	Compliance Monitoring
3	MOD-001-2	Purpose
4	CIP-002-5.1	Guidelines and Technical Basis
5	CIP-003-3a	Appendix 1, Response to Question 1
6	MOD-001-2	Application Guidelines, Rationale for R5
7	PER-005-2	Application Guidelines, Rationale for TO
8	TPL-007-1	Application Guidelines, Requirement R2, R7

List of ROP provisions (other than Appendix 2) where Bulk Power System occurs: The term is used throughout the ROP, including all appendices.

List defined terms that include Bulk Power System in definition narrative:

	Glossary
1	N/A (not a glossary term)
2	N/A
3	No
4	N/A
5	N/A

	ROP
1	Cyber Security Incident
2	Electric Reliability Organization or ERO
3	Interconnection
4	NERC Compliance Registry, Compliance Registry or NCR
5	Receiving Entity

6	N/A
7	N/A
8	Reliability Standard
9	Reliable Operation
10	N/A
11	N/A
12	N/A

6	Regional Criteria
7	Registered Entity
8	Reliability Standard
9	Reliable Operation
10	Remedial Action Directive
11	Sector
12	Submitting Entity

List of other defined terms that are included in the Bulk Power System definition narrative:

Glossary: facilities, transmission, system

ROP: Facilities, transmission, system

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: Both the ROP and Glossary definitions have been approved by FERC as tracking the definition provided in the Federal Power Act. (*See*, Glossary: FERC Order; and ROP: FERC Order on Compliance Filing, FERC Order Approving Amendments to the ROP). However, there are a number of differences in the definition narrative, including: (1) the ROP definition does not contain a hyphen for Bulk Power System, but the Glossary term does; (2) the ROP capitalizes the term "Facilities" in part (A) but the Glossary does not; (3) the ROP contains the language "electric energy supply and transmission network" whereas the Glossary provides "electric energy transmission network;" and, (4) the ROP contains the word "generating" whereas the Glossary contains "generation."

How/why the terms may be applied differently as a result of the differences: The differences are relatively minor and do not result in inconsistent or different application of the term in the Glossary or ROP. However, the different language (*i.e.*, "electric energy supply and transmission network" vs. "electric energy transmission network") may lead to confusion or imply that the terms are intended to have different meanings. Because both terms are intended to have the meaning of the definition in the Federal Power Act, the standard drafting team believes these differences should be eliminated.

Proposed revision(s): The SDT proposes revisions to both the Glossary and ROP definition in order to align the two terms and maintain consistency with the Federal Power Act. Redlines of both definitions are provided below.

Redline of Glossary definition:

Bulk- Power System:

(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and
(B) electric energy from generation facilities needed to maintain transmission system reliability.
The term does not include facilities used in the local distribution of electric energy. (In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.) Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.

Redline of ROP, Appendix 2 definition:

Bulk Power System" means, depending on the context:

(i) (A) ~~Facilities~~ facilities and control systems necessary for operating an interconnected electric energy ~~supply and~~ transmission network (or any portion thereof)~~;~~ and

(B) electric energy from generati~~o~~n~~g~~ facilities needed to maintain transmission system reliability.

The term does not include facilities used in the local distribution of electric energy. [++] (In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.) Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.

(ii) Solely for purposes of Appendix 4E, Bulk Electric System.

Justification for decision: Both the ROP and Glossary definitions have been approved by FERC (*See*, Glossary: FERC Order; and ROP: FERC Order on Compliance Filing, FERC Order Approving Amendments to the ROP). However, there are a number of differences, mostly minor, in the two definitions. The different language may be perceived to mean that the terms are intended to have different meanings, when this is not the case. There is no reason for the terms to have differing definitions, as both terms are intended to have the meaning of the definition in Section 215 of the Federal Power Act. The SDT revisions align the terms by eliminating the unnecessary differences. Below is a summary of the proposed revisions:

(1) The SDT is proposing to remove the hyphen from the term Bulk-Power System in the Glossary because it is not being used as a compound modifier (two words coupled together to make an adjective). Because "bulk" is being used to describe the "power grid," no hyphen is needed. If instead, "bulk power" was being used to describe "grid," then a hyphen (compound modifier) would be appropriate to connect bulk-power.

(2) In both definitions, added a clarification sentence to explain that the defined terms contained in the definition (*e.g.*, system, transmission) are not capitalized in order to match the Federal Power Act definition (which does not capitalize the terms).

(3) In part (A) of the ROP definition, changed "Facilities" to lowercase "facilities" for the reason outlined in (2).

(4) In the ROP, revised "generating" to "generation" in order to match the Federal Power Act and Glossary definitions.

(5) In the ROP, revised "electric energy supply and transmission network" to "electric energy transmission network" in order to match the Federal Power Act and Glossary definitions.

Term 17: Generator Operator

Glossary Definition (differences in definition narrative indicated in red)	ROP Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	the entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.**	The SDT is proposing to revise the Glossary definition to align with the ROP. Redline of Glossary definition: The entity that operates generating Facility(ies) ~~unit(s)~~ and performs the functions of supplying energy and Interconnected Operations Services. Additionally, the SDT notes that during the course of its work on this project, the team reviewed and assessed the quality of the definition of "Facility." The SDT believes the clarity and content of the current definition could be improved. As a result, the SDT will draft a SAR proposing to revise the definition in order to address the issues identified by the SDT.

I. HISTORY AND BACKGROUND INFORMATION REGARDING "GENERATOR OPERATOR" DEFINITION

History of Glossary term:

- Original and current version – **Effective as of 03/16/07**
  - FERC Order No. 693 (03/16/07): "In conclusion, the Commission approves the glossary. Further, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs ERO to modify the glossary through the Reliability Standards development process to…(2) modify the definition of "transmission operator" and "generator operator" to include aspects unique to ISO, RTO and pooled resource organizations… (P 1899)

History of ROP term:

- Original version: Effective 01/31/2012 – 03/18/15
  - NERC Petition to Revise ROP (11/29/11): "The purposes of the proposed revisions are (1) to place all definitions of defined terms used anywhere in the ROP in a single, readily-accessible location (proposed new Appendix 2); (2) to capitalize defined terms throughout the ROP where such terms are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the ROP but are not defined terms." (p. 1)
  - FERC Order approving amendments to the ROP (01/31/2012): "Pursuant to section 215(f) of the FPA and section 39.10(a) of the Commission's regulations, we approve the proposed revisions to the NERC Rules of Procedure. We agree with NERC that the revisions do not substantively change any original definitions in the Rules of Procedure; moreover, the Rules of Procedure remains procedurally and substantively the same. In addition, the creation of Appendix 2 offers a central, readily-accessible document containing all defined terms as used within the Rules of Procedure." (P 10)

- Current version: **Effective as of 03/19/15**
  - Revisions were made by the Risk Based Registration Initiative – Replaced "units" with "Facility(ies)"
  - NERC Petition (12/11/14)
  - FERC Order (03/19/15) – Approving revised definition

II. USAGE OF DEFINED TERM: GENERATOR OPERATOR

List of usage of the term Generator Owner within Reliability Standards:

	Reliability Standard	Location
1	All Reliability Standards applicable to GOPs	Applicability
2	CIP-002-5.1	Attachment 1
3	IRO-010-1a	Appendix 1
4	PER-005-2	Application Guidelines
5	PRC-023-3	Attachment B
6	TOP-001-1a	Appendix 1
7	VAR-001-4	Application Guidelines
8	VAR-002-3	Application Guidelines
9	VAR-002-4	Application Guidelines

List of ROP provisions (other than Appendix 2) where Generator Operator occurs:

	ROP provision	Page # [Link to ROP]
1	Section 302.1	8 of 483
2	Appendix 5A: Organization Registration and Certification Manual	401 of 483
3	Appendix 5B: Statement of Compliance Registry Criteria (Revision 5.2)	433-438 of 483
4	Appendix 8: NERC Blackout and Disturbance Response Procedures, Attachment E	482 of 483

List defined terms that include Generator Operator in definition narrative:

	Glossary
1	Bulk Electric System
2	Control Center
3	Nuclear Plant Generator Operator
4	Nuclear Plant Interface Requirements
5	System Operator

	ROP
1	Bulk Electric System
2	N/A
3	N/A
4	N/A
5	N/A

List of other defined terms that are included in the Generator Operator definition narrative:

Glossary: Interconnected Operations Services

ROP: Facility(ies), Interconnected Operations Services

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: The definitions were previously aligned. However, as part of the Risk Based Registration (RBR) Initiative undertaken in 2014, the ROP definition was revised and the word "unit" was replaced with "Facility(ies)." The RBR team believed it necessary to replace "unit" with "Facility(ies)" in order to incorporate the BES Definition. The RBR project work focused on changes to the ROP, and the team did not consider whether changes were needed to align any affected Glossary definitions.

How/why the terms may be applied differently as a result of the differences: The term "unit" is not a defined term in the Glossary or ROP. However, "unit" or "generating unit" are both used in definition narratives of a number of Glossary (and ROP) terms, including, but not limited to: Blackstart Resource, Bulk Electric System, Cranking Path, Economic Dispatch, Forced Outage, Host Balancing Authority, and Joint Control. The Merriam-Webster definition for unit is, "a single thing, person, or group that is a constituent of a whole." Click here for the Merriam-Webster website.

The term "Facility," on the other hand, is a defined term in the Glossary and ROP. Facility is defined as, "a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." Also, the term "Element" (which is used in the definition of Facility) is, "any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components."

Proposed revision(s): The SDT proposes to revise the Glossary definition to align with the ROP. No changes are proposed to the ROP.

> **Redline of Glossary definition:**
> The entity that operates generating Facility(ies) ~~unit(s)~~ and performs the functions of supplying energy and Interconnected Operations Services.

Justification for decision: The SDT is proposing to revise the Glossary definition to align with the ROP. This is because the term "unit" (used in the current Glossary definition) is not a NERC defined term, and thus introduces the possibility of inconsistent use or application of the definition. The ROP definition provides greater clarity because it uses the term "Facility(ies)," which is defined by NERC as, "a set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.*, a line, a generator, a shunt compensator, transformer, etc.)." (*See also*, NERC Limited Answer to RBR Comments, pp. 6-7: "Finally, NERC's proposed changes to the definitions of "Generator Owner" and "Generator Operator" which include replacing the undefined term "generating units" with the term "Facilities," are appropriate. The term "Facilities" is defined in the NERC Glossary as a Bulk Electric System element, which ties in directly to the new BES definition. Use of the term "Facilities" has allowed NERC to eliminate the Part III threshold criteria and use the new Bulk Electric System core definition, inclusions and exclusions to identify Bulk Electric System generator assets.")

Term 18: Generator Owner

Glossary Definition (differences in definition narrative indicated in red)	ROP Appendix 2 Definitions (differences in definition narrative indicated in red)	SDT proposed revisions
Entity that owns and maintains generating units.	an entity that owns and maintains generating Facility(ies).**	The SDT is proposing to revise the Glossary definition to align with the ROP. Redline of Glossary definition: Entity that owns and maintains generating Facility(ies)~~units~~. Additionally, the SDT notes that during the course of its work on this project, the team reviewed and assessed the quality of the definition of "Facility." The SDT believes the clarity and content of the current definition could be improved. As a result, the SDT will draft a SAR proposing to revise the definition in order to address the issues identified by the SDT.

I. HISTORY AND BACKGROUND INFORMATION REGARDING "GENERATOR OWNER" DEFINITION

History of Glossary term:

- Original and current version – **Effective as of 03/16/07**
  - FERC Order No. 693 (03/16/07): "The Commission approves the glossary. The terms defined in the glossary have an important role in establishing consistent understanding of the Reliability Standards Requirements and implementation. The approval of the glossary will provide continuity in application of the glossary definitions industry-wide, and will eliminate multiple interpretations of the same term or function, which may otherwise create miscommunication and jeopardize Bulk-Power System reliability…" (P 1893)

History of ROP term:

- Original version: Effective 01/31/2012 – 03/18/15
  - NERC Petition to Revise ROP (11/29/11): "The purposes of the proposed revisions are (1) to place all definitions of defined terms used anywhere in the ROP in a single, readily-accessible location (proposed new Appendix 2); (2) to capitalize defined terms throughout the ROP where such terms are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the ROP but are not defined terms." (p. 1)
  - FERC Order Approving Amendments to the ROP (01/31/2012): "Pursuant to section 215(f) of the FPA and section 39.10(a) of the Commission's regulations, we approve the proposed revisions to the NERC Rules of Procedure. We agree with NERC that the revisions do not substantively change any original definitions in the Rules of Procedure; moreover, the Rules of Procedure remains procedurally and substantively the same. In addition, the creation of Appendix 2 offers a central, readily-accessible document containing all defined terms as used within the Rules of Procedure." (P 10)

- Current version: **Effective as of 03/19/15**
  - Revisions were made by the Risk Based Registration Initiative – Replaced "units" with "Facility(ies)"
  - NERC Petition (12/11/14)
  - FERC Order (03/19/15) – Approving revised definition

II. USAGE OF DEFINED TERM: GENERATOR OWNER

List of usage of the term Generator Owner within Reliability Standards:

	Reliability Standard	Location
1	All Reliability Standards applicable to GOs	
2	PRC-005-1.1b	Appendix 1 Appendix 2
3	PRC-025-1	Attachment 1 Application Guideline
4	PRC-026-1	Application Guideline
5	TOP-005-2a	Appendix 2
6	TPL-007-1	Application Guideline
7	CIP-002-5.1	BES Cyber System Categorization
8	FAC-001-2	Application Guideline
9	FAC-003-3	Guideline & Technical Basis
10	IRO-010-1a	Appendix 1
11	MOD -025-2	Attachment 1
12	MOD-026-1	Attachment 1
13	MOD-027-1	Attachment 1
14	MOD-032-1	Application Guideline
15	PRC-004-3	Application Guideline
16	PRC-004-4	Application Guideline

List of ROP provisions (other than Appendix 2) where Generator Owner occurs:

	ROP provision	Page # [Link to ROP]
1	Section 302.1	8 of 483
2	Section 1702.1	105 of 483
3	Appendix 5A: Organization Registration and Certification Manual	401 of 483
4	Appendix 5B: Statement of Compliance Registry Criteria (Revision 5.2)	433 of 483 434 of 483
5	Appendix 8: NERC Blackout and Disturbance Response Procedures, Attachment E	482 of 483

List defined terms that include Generator Owner in definition narrative:

	Glossary
1	Bulk Electric System
2	Nuclear Plant Generator Operator
3	Right-of-Way
4	Transmission Customer
5	Vegetation Inspection

	ROP
1	Bulk Electric System
2	N/A
3	N/A
4	Transmission Customer
5	N/A

List of other defined terms that are included in the Generator Owner definition narrative:

Glossary: None
ROP: Facility(ies)

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: The definitions were previously aligned. However, as part of the Risk Based Registration (RBR) Initiative undertaken in 2014, the ROP definition was revised and the word "unit" was replaced with "Facility(ies)." The RBR team believed it necessary to replace "unit" with "Facility(ies)" in order to incorporate the BES Definition. The RBR project work focused on changes to the ROP, and the team did not consider whether changes were needed to align any affected Glossary definitions.

How/why the terms may be applied differently as a result of the differences: The term "unit" is not a defined term in the Glossary or ROP. However, "unit" or "generating unit" are both used in definition narratives of a number of Glossary (and ROP) terms, including, but not limited to: Blackstart Resource, Bulk Electric System, Cranking Path, Economic Dispatch, Forced Outage, Host Balancing Authority, and Joint Control. The Merriam-Webster definition for unit is, "a single thing, person, or group that is a constituent of a whole." Click here for the Merriam-Webster website.

The term "Facility," on the other hand, is a defined term in the Glossary and ROP. Facility is defined as, "a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." Also, the term "Element" (which is used in the definition of Facility) is, "any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components."

Proposed revision(s): The SDT proposes to revise the Glossary definition to align with the ROP. No changes are proposed to the ROP.

Redline of Glossary definition:
Entity that owns and maintains generating Facility(ies)~~units~~.

Justification for decision: The SDT is proposing to revise the Glossary definition to align with the ROP. This is because the term "unit" (used in the current Glossary definition) is not a NERC defined term, and thus introduces the possibility of inconsistent use or application of the definition. The ROP definition provides greater clarity because it uses the term "Facility(ies)," which is defined by NERC as, "a set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.*, a line, a generator, a shunt compensator, transformer, etc.)." (*See also*, NERC Limited Answer to RBR Comments, pp. 6-7: "Finally, NERC's proposed changes to the definitions of "Generator Owner" and "Generator Operator" which include replacing the undefined term "generating units" with the term "Facilities," are appropriate. The term "Facilities" is defined in the NERC Glossary as a Bulk Electric System element, which ties in directly to the new BES definition. Use of the term "Facilities" has allowed NERC to eliminate the Part III threshold criteria and use the new Bulk Electric System core definition, inclusions and exclusions to identify Bulk Electric System generator assets.")

Term 29: Net Energy for Load or NEL

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.	net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.	No changes to either ROP or Glossary. The SDT recommends the terms remain unaligned. The differences in the definition narratives are appropriate given the differing uses of the term within the Glossary and ROP.

I. HISTORY AND BACKGROUND INFORMATION REGARDING "NET ENERGY FOR LOAD" DEFINITION

History of Glossary term:

- Original and current version: **Effective as of 03/16/07**
  - FERC Order No. 693 (03/16/07): "The Commission approves the glossary. The terms defined in the glossary have an important role in establishing consistent understanding of the Reliability Standards Requirements and implementation. The approval of the glossary will provide continuity in application of the glossary definitions industry-wide, and will eliminate multiple interpretations of the same term or function, which may otherwise create miscommunication and jeopardize Bulk-Power System reliability…" (P 1893)

History of ROP term:

- Original version
  - FERC Order No. 672 (02/03/06): Net Energy for Load means balancing authority area generation (less station use), plus energy received from other balancing authority areas, less energy delivered to balancing authority areas through interchange. It includes balancing authority area losses, but excludes energy required for storage at electric energy storage facilities, such as pumped storage. (P 35, FN 7)
  - FERC Order (07/20/06) - NERC's application proposes to base allocation of all costs for statutory activities on net energy for load. (P 155, 167)
  - NERC Non-Governance Compliance Filing (10/18/06): "Net Energy for Load" or "NEL" means net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities. (Proposed Rules of Procedure, Section 202, Specific Definitions)
  - FERC Order Accepting Non-Governance Compliance Filing (01/18/07): "NERC has appropriately revised definitions in its Bylaws and its Rules of Procedure to reflect these same definitions in Order No. 672." (P 223)

- Current version: **Effective as of 01/31/2012**
  - NERC Petition to Revise ROP (11/29/11): "The purposes of the proposed revisions are (1) to place all definitions of defined terms used anywhere in the ROP in a single, readily-accessible location (proposed new Appendix 2)…" (p.1; p. 12: Definition taken from NERC Bylaws, Article 1 and ROP, Section 200).

- FERC Order Approving Amendments to the ROP (01/31/2012): "Pursuant to section 215(f) of the FPA and section 39.10(a) of the Commission's regulations, we approve the proposed revisions to the NERC Rules of Procedure. We agree with NERC that the revisions do not substantively change any original definitions in the Rules of Procedure; moreover, the Rules of Procedure remains procedurally and substantively the same. In addition, the creation of Appendix 2 offers a central, readily-accessible document containing all defined terms as used within the Rules of Procedure." (P 10)

II. USAGE OF DEFINED TERM: NET ENERGY FOR LOAD

List of usage of the term Net Energy for Load within Reliability Standards:

	Reliability Standard
1	MOD-016-1.1
2	MOD-017-0.1
3	MOD-018-0
4	MOD-021-1
5	MOD-031-1
6	TPL-006-0.1

List of ROP provisions (other than Appendix 2) where Net Energy for Load occurs:

	ROP provision	Page # [Link to ROP]
1	Section 804	71 of 483
2	Section 1101.1	84 of 483
3	Section 1101.4	84 of 483
4	Section 1103	93 of 483
5	Appendix 3A: Standards Process Manual – Footnote 10	141 of 483
6	Appendix 3B: Procedures for Election of Members of Standards Committee	186 of 483

List defined terms that include Net Energy for Load in definition narrative:

	Glossary
1	Peak Demand

	ROP
1	N/A

List of other defined terms that are included in the Net Energy for Load definition narrative:

Glossary: Balancing Authority Area

ROP: None

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: The Glossary definition is more specific in that it provides "Balancing Authority Area generation" and "received from other Balancing Authority Areas" whereas the ROP definition refers more broadly to "generation of an electric system" and "received from others."

How/why the terms may be applied differently as a result of the differences: The differences are significant and should remain due to the manner in which these terms are applied in their respective documents (ROP or Glossary). For example, as outlined above, FERC approved the ERO's proposal to base allocation of all costs for

statutory activities on net energy for load (See ROP, Section 1100). In the context of Reliability Standards, the collection of Net Energy for Load data is required for certain modeling standards (See MOD-031-3).

Proposed revision(s): Alignment is not recommended by SDT because the differences in the definition narrative are appropriate given the different uses of the term within the Glossary and ROP.

Justification for decision: The differences are significant and should remain due to the manner in which these terms are applied in their respective documents (ROP or Glossary).

Term 40: Reliability Standard

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.	a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.	The SDT is proposing revisions to both the Glossary and ROP definitions, as follows: Redline of Glossary definition: A requirement, approved by the United States Federal Energy Regulatory Commission under ~~this~~ Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk~~-~~ Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk~~-~~ Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk~~-~~ Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.) Redline of ROP definition: a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk Power System]~~,~~ ~~including without limiting the foregoing,~~ The term includes requirements for the operation of existing bulk-power system [Bulk Power System] ~~Facilities~~facilities, including cyber~~-~~security protection, and ~~including~~ the design of planned additions or modifications to such ~~Facilities~~ facilities to the extent necessary for reliable operation [Reliable Operation] of the bulk-power system [Bulk Power System], but the term does not include any requirement to enlarge ~~Bulk Power System~~ such ~~Facilities~~ facilities or to construct new transmission capacity or generation capacity.++ (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.) In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions. ~~A Reliability Standard~~

		~~shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.~~

I. HISTORY AND BACKGROUND INFORMATION REGARDING "RELIABILITY STANDARD" DEFINITION

History of Glossary term:

- Original version: 03/16/07 - 07/08/13
  - FERC Order No. 693 (03/16/07) - "The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the statutory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary." (P 1894)

- Current version: **Effective as of 07/09/13**
  - Revised by Project 2012-08.1 Phase 1 of the Glossary Updates for Statutory Definitions
  - NERC Petition (05/10/13) - The proposed definition borrows heavily from FPA, but makes slight alterations.

"The term "Reliability Standard" is defined in section 215 of the FPA as follows:

> (3) The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.

The proposed definition of the term "Reliability Standard" for inclusion in the NERC Glossary is as follows:

> "Reliability Standard" means a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk-Power System. The term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk-Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.

As noted herein, the proposed definition of "Reliability Standard" is substantively identical to the definition in section 215 of the FPA, although the terms "Bulk-Power System" and "Reliable Operation" are capitalized to reflect the fact that they are defined terms and slight modifications were necessary to clarify the terms "Commission" and "section" (contained in the section 215 definition of the term "Reliability Standard").

"Commission" refers to the Federal Energy Regulatory Commission in the United States and applicable governmental authorities approving, or recognizing the standard, in other jurisdictions; similarly, "section" has been replaced with "section 215 of the Federal Power Act."

These minor modifications are fully consistent with section 215 and the recognized need for international agreements with the governments of Canada and Mexico to provide for effective compliance with Reliability Standards and the effectiveness of the ERO in the United States and Canada or Mexico. For these reasons, the proposed definition of "Reliability Standard" should be accepted in compliance with the Commission's directive in Order No. 693." (pp. 7-8)

- FERC Order (07/9/13) - Letter order approving proposed definitions

History of ROP term:

- Original version:
  - NERC Non-Governance Compliance Filing (10/18/06): "NERC has also revised definitions in its Rules of Procedure to match definitions in Section 215(a) of the Federal Power Act and/or Part 39 of the Commission's regulations, including 'bulk power system', 'electric reliability organization,' 'reliable operation,' and 'reliability standard'." (pp. 71-72)
    - " 'Reliability standard' means a requirement to provide for reliable operation of the bulk power system, including without limiting the foregoing, requirements for the operation of existing bulk power system facilities, including cyber security protection, and including the design of planned additions or modifications to such facilities to the extent necessary for reliable operation of the bulk power system, but the term does not include any requirement to enlarge bulk power system facilities or to construct new transmission capacity or generation capacity. A reliability standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the applicable governmental authority.' (Citing, Attachment 1, Revised ROP, at Section 202)
  - FERC Order Accepting Non-Governance Compliance Filing (01/18/07): "NERC has appropriately revised definitions in its Bylaws and its Rules of Procedure to reflect these same definitions in Order No. 672." (P 223)

- Current version: **Effective as of 01/31/2012**
  - NERC Petition to Revise ROP (11/29/11): "The purposes of the proposed revisions are (1) to place all definitions of defined terms used anywhere in the ROP in a single, readily-accessible location (proposed new Appendix 2); (2) to capitalize defined terms throughout the ROP where such terms are intended to be used in their defined meanings; and (3) to lower-case other terms that are currently capitalized in the ROP but are not defined terms." (p. 1)
  - FERC Order Approving Amendments to the ROP (01/31/2012): "Pursuant to section 215(f) of the FPA and section 39.10(a) of the Commission's regulations, we approve the proposed revisions to the NERC Rules of Procedure. We agree with NERC that the revisions do not substantively change any original definitions in the Rules of Procedure; moreover, the Rules of Procedure remains procedurally and substantively the same. In addition, the creation of Appendix 2 offers a central, readily-accessible document containing all defined terms as used within the Rules of Procedure." (P 10)

II. USAGE OF DEFINED TERM: RELIABILITY STANDARD

List of usage of the term "Reliability Standard" within the Complete Set of Reliability Standards: The term appears at least 330 times within the Complete Set of NERC Reliability Standards. The overwhelming majority of these uses are in reference to a particular Reliability Standard (*e.g.*, Reliability Standard FAC-003-3). Such uses do not touch upon the concept of "Reliability Standard" in a way that revising the definition of the term would have any material impact. It also appears passim in the "Applicability" Section of the new CIP v5 Standards. Again, revision would have no material impact. Also, it appears in the "Effective Date" of many Reliability Standards. Again, revision would have no material impact.

List of ROP provisions (other than Appendix 2) where Reliability Standard occurs: The term appears over 850 times in the ROP. A number of the ROP provisions refer or apply to Reliability Standards that are currently under development, or are approved by the NERC Board of Trustees, but not yet approved by FERC or another applicable governmental authority.

List defined terms that include Reliability Standard in definition narrative:

	Glossary
1	Burden (not defined term)
2	Compliance Monitor (not defined term)
3	Control Performance Standard (not defined term)
4	Disturbance Control Standard (not defined term)
5	Remedial Action Scheme
6	Extraordinary Contingency (referencing WECC Reliability Standard)
7	Functionally Equivalent Protection System
8	Functionally Equivalent RAS

ROP [Link to ROP]
The term is used in 38 ROP, Appendix 2 definitions.

List of all other defined terms that are included in the Reliability Standard definition narrative:

Glossary: Reliable Operation, Bulk-Power System, facility(ies)
ROP: Reliable Operation, Bulk Power System, Facility, Applicable Governmental Authority

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: The Glossary definition is somewhat more limiting because it defines "Reliability Standard" as a "requirement approved by the United States Federal Energy Regulatory Commission…" The ROP definition is broader than the Glossary definition because it does not include the "approved" language and includes those standards that are not yet FERC-approved.

How/why the terms may be applied differently as a result of the differences: The difference in these definitions is meaningful. The Glossary term is narrower than the ROP term. This difference may cause confusion when applying the definition in the ROP when addressing standards that are currently under development, or approved by the NERC Board of Directors, but not yet FERC-approved.

Proposed revision(s): The drafting team proposes revisions to both the Glossary and ROP definitions.

Redline of Glossary definition:

A requirement, approved by the United States Federal Energy Regulatory Commission under ~~this~~ Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk~~-~~ Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk~~-~~ Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk~~-~~ Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)

Redline of ROP Appendix 2 definition:

a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk Power System]~~., including without limiting the foregoing,~~ The term includes requirements for the operation of existing bulk-power system [Bulk Power System] ~~Facilities~~facilities, including cyber~~-~~security protection, and ~~including~~ the design of planned additions or modifications to such ~~Facilities~~ facilities to the extent necessary for reliable operation [Reliable Operation] of the bulk-power system [Bulk Power System], but the term does not include any requirement to enlarge ~~Bulk Power System~~ such ~~Facilities~~ facilities or to construct new transmission capacity or generation capacity.~~+~~+ (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.) In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions. ~~A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.~~

Justification for decision: The SDT believes the proposed revisions will allow the ROP definition to align with the Glossary definition, which tracks the language in the Federal Power Act. The Glossary was revised through Project 2012-08.1 to address a FERC directive to adopt the Federal Power Act definition. The Project 2012-08.1 drafting team noted in their response to industry comments that any necessary revisions to the ROP definition would be made through a separate project. The Project 2015-04 SDT is now proposing to make these revisions to align the definitions. Because a number of ROP provisions refer or apply to Reliability Standards that are currently under development, or are approved by the NERC Board of Trustees, but not yet FERC-approved, the SDT is proposing to add qualifying language to the ROP definition. The ROP definition explains that in certain contexts, "Reliability Standard" may refer to a standard that is in the process of being developed, and not yet FERC-approved.

Term 44: Sink Balancing Authority

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.	the Balancing Authority in which the Load (sink) is located for an Interchange Transaction.**	The SDT is proposing to revise the ROP definition to align with the Glossary definition. Redline of ROP definition: the Balancing Authority in which the ~~Load~~ load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.**

I. HISTORY AND BACKGROUND INFORMATION REGARDING "SINK BALANCING AUTHORITY" DEFINITION

History of Glossary term:

- Original version: FERC approved 3/16/2007: "The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)"

- Current version: **Effective as of 10/01/2014**
  - Revisions made by Project 2008-12 Coordinate Interchange Standards
  - NERC Petition (02/27/2014) - "The proposed revisions to "Sink Balancing Authority" are intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange." (p. 33)
  - FERC Order (06/30/2014) – Letter order approving the revised Glossary definition

History of ROP term:

- Current version: **Effective as of 07/01/13**
  - NERC Petition (11/29/2011) - Added Appendix 2 to ROP and adopted existing Glossary definition for Sink Balancing Authority (p. 14)
  - FERC Order (01/31/2012) - "These revisions are being proposed as a result of P 93 of the Commission's Order issued October 21, 2010, in Docket No. RR10-11-000, in which the Commission invited NERC to submit a filing making consistent use of defined terms throughout the ROP and Appendices." (p. 1)
  - NERC Petition (01/25/12) – Minor revisions to "Sink Balancing Authority" to reflect changes resulting from new BES Definition

II. USAGE OF DEFINED TERM: SINK BALANCING AUTHORITY

List of usage of the term Sink Balancing Authority within Reliability Standards:

	Reliability Standard
1	BAL-006-2
2	INT-001-3
3	INT-004-3.1
4	INT-005-3

5	INT-006-4
6	INT-010-2.1
7	IRO-006-East-1
8	MOD-028-2

List of ROP provisions (other than Appendix 2) where Sink Balancing Authority occurs: None.

List defined terms that include Sink Balancing Authority in definition narrative:

	Glossary
1	Intermediate Balancing Authority
2	Request for Interchange (Archive)
3	Contributing Schedule
4	Relief Requirement (Archive)

	ROP
1	N/A
2	N/A
3	N/A
4	N/A

List of other defined terms that are included in the Sink Balancing Authority definition narrative:

Glossary: Balancing Authority, load, Interchange Transaction, Interchange Schedule
ROP: Balancing Authority, Load, Interchange Transaction

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: There are two differences between the Glossary and ROP definitions: (1) the Glossary definition does not capitalize the term "load" whereas the ROP definition does; and, (2) the Glossary definition includes "an Interchange Transaction and any resulting Interchange Schedule" whereas the ROP definition only provides "an Interchange Transaction."

How/why the terms may be applied differently as a result of the differences: The language added through the Project 2008-12 Coordinate Interchange Standards did not impact or change the meaning of the definitions. The changes to the Glossary definition clarified the various Balancing Authorities involved in the implementation of Interchange and their relationship to Interchange. Additionally, the Glossary definition correctly uses lowercase for "load" rather than the defined term, which is appropriate given that the use of load in the narrative does not appear to have the meaning of the NERC definition. The SDT is proposing to correct the ROP definition to reflect the lowercase usage of the word "load" so that it is aligned with the Glossary definition.

Proposed revision(s): The SDT proposes to revise the ROP definition to align with the Glossary definition.

Redline of ROP definition:

the Balancing Authority in which the ~~Load~~ load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.**

Justification for decision: The original Glossary definition became effective in March 2007. The ROP definition adopted the Glossary definition when Appendix 2 was created in 2012. Note that the ROP definition is marked with a double asterisk (**), indicating it was taken from the Glossary. Subsequently, in 2014, the Glossary term was revised to provide greater clarity. The ROP definition was not updated to reflect the revised Glossary definition.

Term 45: Source Balancing Authority

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.	the Balancing Authority in which the generation (source) is located for an Interchange Transaction.**	The SDT is proposing to revise the ROP definition to align with the Glossary definition. Redline of ROP definition: the Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.**

I. HISTORY AND BACKGROUND INFORMATION REGARDING "SOURCE BALANCING AUTHORITY" DEFINITION

History of Glossary term:

- Original version: Effective dates 03/16/07 – 09/30/14 (Version 0: "The Balancing Authority in which the generation (source) is located for an Interchange Transaction. This will also be a Sending Balancing Authority for the resulting Interchange Schedule.")

- Current version: **Effective as of 10/01/2014**
  - Revisions made by Project 2008-12 Coordinate Interchange Standards
  - NERC Petition (02/27/14) - "The proposed revisions to "Source Balancing Authority" are intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange." (p. 34)
  - FERC Order (06/30/2014) – FERC letter order approving revised Glossary definition

History of ROP term:

- Current version: **Effective as of 01/31/2012**
  - NERC Petition (11/29/2011) - Added Appendix 2 to ROP and adopted existing Glossary definition for Adjacent Balancing Authority (see p. 9)
  - FERC Order (01/31/2012) - "These revisions are being proposed as a result of P 93 of the Commission's Order issued October 21, 2010, in Docket No. RR10-11-000, in which the Commission invited NERC to submit a filing making consistent use of defined terms throughout the ROP and Appendices." (p. 1)

II. USAGE OF DEFINED TERM: SOURCE BALANCING AUTHORITY

List of all usage of the term Source Balancing Authority within Reliability Standards:

	Reliability Standard
1	BAL-006-2
2	INT-005-3
3	INT-006-4
74	MOD-028-2

List of all ROP provisions (other than Appendix 2) where Source Balancing Authority occurs: None.

List all defined terms that include Source Balancing Authority in definition narrative:

	Glossary
1	Intermediate Balancing Authority
2	Contributing Schedule

	ROP
1	N/A
2	N/A

List of all other defined terms that are included in the Source Balancing Authority definition narrative:

Glossary**:** Balancing Authority, Interchange Transaction, Interchange Schedule

ROP: Balancing Authority, Interchange Transaction

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: The Glossary definition includes "and for any resulting Interchange Schedule" whereas the ROP does not.

Explain how/why the terms may be applied differently as a result of the differences: The language added through the Project 2008-12 Coordinate Interchange Standards did not impact or change the meaning of the definitions. The changes to the Glossary definition clarified the various Balancing Authorities involved in the implementation of Interchange and their relationship to Interchange.

Proposed revision(s). The SDT proposes to revise the ROP definition to align with the Glossary definition.

Redline of ROP definition:

the Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.**

Justification for decision: The original Glossary definition became effective in March 2007. The ROP definition adopted the Glossary definition when Appendix 2 was created in 2012. Note that the ROP definition is marked with a double asterisk (**), indicating it was taken from the Glossary. Subsequently, in 2014, the Glossary term was revised to provide greater clarity. The ROP definition was not updated to reflect the revised Glossary definition.

Term 48: System Operating Limit (SOL)

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)	the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.**	The SDT is proposing to revise both the Glossary and ROP, as follows: Redline of Glossary definition: The value (such as MW, MVar, ~~A~~amperes, ~~Frequency~~ frequency or ~~Volts~~volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (~~Applicable~~ applicable pre- and post-Contingency ~~equipment~~ Equipment Ratings or ~~facility~~ Facility ~~ratings~~Ratings) • ~~Transient~~ transient ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Stability~~ stability ~~Limits~~limits) • ~~Voltage~~ voltage ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Stability~~stability) • ~~System~~ system ~~Voltage~~ voltage ~~Limits~~ limits (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Limits~~limits) Redline of ROP definition: the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • facility ratings (applicable pre- and post-contingency equipment ratings or facility ratings) • transient stability ratings (applicable pre- and post-contingency stability limits) • voltage stability ratings (applicable pre- and post-contingency voltage stability) • system voltage limits (applicable pre- and post-contingency voltage limits).**

I. HISTORY AND BACKGROUND INFORMATION REGARDING "SYSTEM OPERATING LIMIT" DEFINITION

History of Glossary term:

- Original and current version: **Effective date 07/08/13**
  - FERC Order No. 693 (03/16/07) - "The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the statutory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary." (P 1894)

History of ROP term:

- Current version: **Effective as of 01/31/2012**
  - NERC Petition (11/29/2011) - Added Appendix 2 to ROP and adopted existing Glossary definition for System Operating Limit (see p. 14)
  - FERC Order (01/31/2012) - "These revisions are being proposed as a result of P 93 of the Commission's Order issued October 21, 2010, in Docket No. RR10-11-000, in which the Commission invited NERC to submit a filing making consistent use of defined terms throughout the ROP and Appendices."

II. USAGE OF DEFINED TERM: SYSTEM OPERATING LIMIT

List of usage of the term "System Operating Limit" within Reliability Standards: The term appears over fifty times within the Complete Set of NERC Reliability Standards. A majority of these occurrences are in the FAC, IRO and TOP standards (the term also appears in CIP, EOP, MOD, PER, and PRC standards).

List of ROP provisions (other than Appendix 2) where System Operating Limit occurs:

	ROP provision	Page # [Link to ROP]
1	Appendix 4C – CMEP, Section 1.1.11	216 of 483
2	NERC Blackout and Disturbance Response Procedures	468 of 483

List defined terms that include System Operating Limit in definition narrative:

	Glossary
1	Burden
2	Constrained Facility
3	N/A
4	Interconnection Reliability Operating Limit
5	Total Flowgate Capability

	ROP
1	N/A
2	N/A
3	Exception Report
4	Interconnection Reliability Operating Limit
5	N/A

List of other defined terms that are included in the System Operating Limit definition narrative:

Glossary: system, Facility Rating, Contingency, Equipment Rating

ROP: system

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: The Glossary definition explains that System Operating Limits are based on certain operating criteria, and it provides a non-exhaustive listing of what that operating criteria may be. The ROP does not contain this additional level of detail.

How/why the terms may be applied differently as a result of the differences: The definitions are similar, however, the Glossary provides more clarity by giving examples of what the operating criteria might be. While the Glossary definition may provide more clarity with the examples, the definitions are consistent with one another and the differences should not result in different application of the term.

Proposed revision(s): The SDT is proposing revisions to both the Glossary and ROP definitions.

Redline of Glossary definition:

The value (such as MW, MVar, ~~A~~amperes, ~~Frequency~~ frequency or ~~Volts~~volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (~~Applicable~~ applicable pre- and post-Contingency ~~equipment~~ Equipment Ratings or ~~facility~~ Facility ~~ratings~~Ratings)
- ~~Transient~~ transient ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Stability~~ stability ~~Limits~~limits)
- ~~Voltage~~ voltage ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Stability~~stability)
- ~~System~~ system ~~Voltage~~ voltage ~~Limits~~ limits (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Limits~~limits).

Redline of ROP definition:

the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- facility ratings (applicable pre- and post-contingency equipment ratings or facility ratings)
- transient stability ratings (applicable pre- and post-contingency stability limits)
- voltage stability ratings (applicable pre- and post-contingency voltage stability)
- system voltage limits (applicable pre- and post-contingency voltage limits).**

Justification for decision: The ROP definition adopted the Glossary definition when Appendix 2 was created in 2012. Note that the ROP definition is marked with a double asterisk (**), indicating it was taken from the Glossary. However, despite the double asterisk (**) indicator, the ROP definition only adopted a portion of the Glossary definition. The SDT is proposing to align the ROP with the Glossary definition. The Glossary definition

provides more clarity with the non-exhaustive list of examples. Additionally, the SDT revised the Glossary definition to lowercase those terms that are not defined terms, and thus, should not be capitalized in the definition narrative.

Part IV: Group 2 recommendations

There are a total of six (6) Group 2 cross-over terms:

Term 8: Critical Assets

Term 9: Critical Cyber Assets

Term 10: Cyber Assets

Term 11: Cyber Security Incident

Term 25: Interconnection

Term 46: Special Protection System

The SDT is recommending revisions to one (1) of the Group 2 cross-over terms. Below is an overview of the SDT research, assessment, proposed revision(s), and justification for each of the recommendations.

CIP-RELATED CROSS-OVER TERMS

Term 8: Critical Assets

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
Glossary term (inactive 03/31/16): Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.**	The SDT is not proposing revisions to the cross-over terms at this time. This is because the changes that would be necessary to align the terms would necessitate a large number of other changes that are outside the scope of the SAR for this project. For the reasons outlined below, the SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.

Term 9: Critical Cyber Assets

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
Glossary term (inactive 03/31/2016): Cyber Assets essential to the reliable operation of Critical Assets.	Cyber Assets critical to the reliable operation of Critical Assets.**	The SDT is not proposing revisions to the cross-over terms at this time. This is because the changes that would be necessary to align the terms would necessitate a large number of other changes that are outside the scope of the SAR for this project. For the reasons outlined below, the SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.

Term 10: Cyber Assets

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
Current definition (inactive 3/31/16):		The SDT is not proposing revisions to the cross-over terms at this time. This is because the changes that

Programmable electronic devices and communication networks including hardware, software, and data. Revised definition (effective 4/1/2016): Programmable electronic devices, including the hardware, software, and data in those devices.	programmable electronic devices and communication networks including hardware, software, and data.** programmable electronic devices and communication networks including hardware, software, and data.**	would be necessary to align the terms would necessitate a large number of other changes that are outside the scope of the SAR for this project. For the reasons outlined below, the SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.

Term 11: Cyber Security Incident

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
Current definition (inactive 03/31/16): Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset. Revised definition (effective 04/01/16): A malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.	any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.++ any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.++	The SDT is not proposing revisions to the cross-over terms at this time. This is because the changes that would be necessary to align the terms would necessitate a large number of other changes that are outside the scope of the SAR for this project. For the reasons outlined below, the SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.

I. HISTORY AND BACKGROUND INFORMATION REGARDING THE CIP-RELATED CROSS OVER TERMS

In 2008, in Order No. 706, FERC approved a number of revised CIP standards and CIP-related Glossary definitions, including the cross-over terms that are currently under review in this project. Thereafter, in 2011, NERC filed a Petition requesting approval to create a ROP Appendix 2 which would house all of the defined terms used or necessary for the ROP provisions. In 2012, FERC issued an Order Approving Amendments to the ROP. In the ROP, Appendix 2, defined terms that were taken from the Glossary were marked with a double asterisk (**); whereas terms taken from the Federal Power Act were marked with a double plus sign (++). All of the cross-over terms that are currently under review by the SDT were added to the ROP, Appendix 2 in this filing. Of those terms, three terms-- Critical Assets, Critical Cyber Assets, and Cyber Assets-- are marked with a double asterisk (**) because they were

taken from the Glossary; one term-- Cyber Security Incident-- is marked with a double plus sign (++) because it was taken from the Federal Power Act.

In 2012, Project 2008-06 made substantial revisions to the CIP Reliability Standards, including revisions to a number of the defined terms used therein. In NERC's petition for approval of the revised standards, "NERC proposes nineteen CIP-related definitions for inclusion in the NERC Glossary. This includes fifteen new definitions and four revised definitions, as well as the retirement of two definitions." See, FERC Order No. 791 P 113.
The 15 newly proposed Glossary definitions included:

1. BES Cyber Asset
2. BES Cyber System
3. BES Cyber System Information
4. CIP Exceptional Circumstances
5. CIP Senior Manager
6. Control Center
7. Dial-up Connectivity
8. Electronic Access Control or Monitoring Systems (EACMS)
9. Electronic Access Point (EAP)
10. External Routable Connectivity
11. Interactive Remote Access
12. Intermediate System
13. Physical Access Control Systems (PACS)
14. Protected Cyber Assets (PCA)
15. Reportable Cyber Security Incident

Also, NERC proposed revisions to four existing Glossary definitions:

1. Cyber Assets
2. Cyber Security Incident
3. Electronic Security Perimeter (ESP)
4. Physical Security Perimeter (PSP)

Further, NERC proposed to retire two existing Glossary definitions:

1. Critical Assets
2. Critical Cyber Assets

These proposed revisions to the Glossary terms were approved by FERC, and become effective March 31, 2016 (retired terms) and April 01, 2016 (new and revised terms). (*See*, FERC Order No. 791). However, no conforming changes were proposed for the defined terms contained in the ROP, Appendix 2. As a result, beginning March 31, 2016, a number of CIP-related defined terms will not be aligned.

II. USAGE OF CIP-RELATED DEFINED TERMS

The four (4) cross-over terms at issue are used throughout the CIP Reliability Standards. Also, the terms are used in a number of ROP provisions, including:

1. Section 400 – Compliance Enforcement, Section 401.10 and 403.13 (*see* pp. 29-39 of 483);
2. Section 1500 – Confidential Information (*see*, p. 96 of 483);
3. Appendix 4C: Compliance Monitoring and Enforcement Program, Section 1.1.5 – Definitions (*see*, p. 262 of 483);
4. Appendix 4C: Compliance Monitoring and Enforcement Program – Attachment 2 - Section 1.5.10, 1.7.4 (*see*, pp. 291, 299, 301 of 483);

5. Appendix D – Technically Feasible Exception Procedure (*see*, pp. 309-310 of 483);
6. Compliance and Certification Committee Hearing Procedures - 1.1.5 Definitions (*see*, pp. 334, 336, 357, 363, 364 of 483);
7. Appendix 5B – Statement of Compliance Registry Criteria (see, p. 438 of 483);
8. Hearing Procedures for Use in Appeals of Certification Matters (*see*, pp. 373, 384, 389 of 483)

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

The SDT is not proposing any revisions to the cross-over terms at this time. This is because the changes that are necessary to align the four cross-over terms would also necessitate a large number of other changes that are outside the scope of the SAR for this project. For example, if changes were made to revise the ROP definition to align with the future enforceable Glossary definition of Cyber Security Incident, three (3) new defined terms would need to be introduced to the ROP-- BES Cyber System, Physical Security Perimeter and Electronic Security Perimeter. Also, the defined term "BES Cyber System" contains the defined term "BES Cyber Asset," which is not defined in the ROP. These four defined terms would need to be added to the ROP because they are not currently defined terms in the ROP, and the definition narratives that would be adopted contain the defined terms.

Another example is the terms, Critical Asset and Critical Cyber Asset, which were retired by the Project 2008-06 team. The CIP version 5 drafting team retired these two terms in the Glossary because the revisions associated with the Version 5 CIP standards "moves away from the CIP version 4 'bright-line' approach of only identifying Critical Assets (and applying CIP requirements only to their associated Critical Cyber Assets), to requiring a minimum classification of 'Low Impact' for all BES Cyber Systems." (See, FERC Order No. 791, P14). In conjunction with the retirement of these two Glossary terms, however, the CIP SDT made a number of revisions to other defined terms and added new definitions to reflect the paradigm shift to classifying BES Cyber Systems. Therefore, in order for this drafting team to adopt the approach taken by the CIP version 5 changes, the team could not simply retire the two cross-over terms that are currently within the scope of the SAR. Rather, the team would have to make all of the other corresponding and necessary changes that were made in conjunction with the CIP version 5 work. For example, the team added the new term, "BES Cyber Asset" to replace the retired terms. This is not a defined term in the ROP, so it would need to be added to Appendix 2. The Glossary definition of "BES Cyber Asset" includes two defined terms-- Electronic Security Perimeter and Cyber Asset. These two defined terms would need to be added to the ROP and align with the Glossary definition.

Additionally, any changes to the ROP definitions would necessitate a thorough review and analysis of the provisions of the ROP that use any of those terms-- both defined and lowercase usage. This is because the ROP currently contains a number of provisions which use the cross-over terms according to the manner in which they are currently defined in the ROP. The alignment changes may alter or affect the meaning of these ROP provisions (see above listing for examples of ROP provisions that use the current ROP definitions).

For the reasons outlined above, the SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.

Term 25: Interconnection

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
Currently effective (inactive as of 06/30/16): When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT. FERC-approved (effective date 07/01/16) When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.	a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++	The SDT is proposing to revise both the Glossary and ROP definitions (effective no earlier than 07/01/16), as follows: Redline of Glossary definition: A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec. Redline of ROP definition: a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++ When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.**

I. HISTORY AND BACKGROUND INFORMATION REGARDING "INTERCONNECTION" DEFINITION

History of Glossary term:

- Original and current version: Effective 03/16/07 – current
  - FERC Order No. 693 (03/16/07) "When capitalized, any one of the three major electric system networks in North America: Eastern Western, and ERCOT." (P 1898)

- Future version: **Effective beginning 07/01/16**
  - Revised by Project 2010-14.1 - Phase 1 Balancing Authority Reliability-based Controls.
  - NERC Petition (04/02/14) – Revised definition to include Quebec interconnection.
  - FERC Order No. 810 (04/16/15) – Revised definition approved.

History of ROP term:

- Original version: Effective 03/17/07 – 01/30/12). Version 0: "Interconnection" means an electric energy supply and transmission network in which the component electric facilities are interconnected and operated synchronously and to which the only connections to other electric networks are asynchronous. (*See*, FERC Order Certifying NERC as ERO).

- Revised and current version: **Effective as of 01/31/2012**
  - o FERC Order (01/31/2012) – The current version is taken from 18 C.F.R. Part 39.1 and the Federal Power Act, Section 215.

II. USAGE OF DEFINED TERM: INTERCONNECTION

List of all usage of the term Interconnection within Reliability Standards: The term appears in at least thirty-five (35) times in the Complete Set of Reliability Standards. The majority of the occurrences are in the BAL, EOP, IRO, MOD and TOP standards.

List of all ROP provisions (other than Appendix 2) where Interconnection occurs:

	ROP provision	Page # [Link to ROP]
1	Section 300, 302, 312	8-20 of 483
2	Section 803	70 -71 of 483
3	Section 1102	84 of 483
4	Appendix 3A – Standards Process Manual, Section 9	167 of 483
5	Appendix 5B – Statement of Compliance Registry Criteria (Revision 5.2)	431-434 of 483
6	Appendix 5C – Exceptions to BES Definition	452 of 483
7	NERC Blackout and Disturbance Procedures	469-473 of 483

List all defined terms that include Interconnection in definition narrative:

	Glossary
1	Adverse Reliability Impact
2	Area Control Error
3	Balancing Authority
4	Bulk Electric System
5	Burden
6	Frequency Bias
7	Frequency Bias Setting
8	Frequency Deviation
9	Frequency Regulation
10	Frequency Response Obligation
11	Interchange Distribution Calculator
12	Interconnection Reliability Operating Limit Tv
13	Reporting ACE
14	Tie Line Bias
15	Time Error
16	Time Error Correction

	ROP
1	N/A
2	N/A
3	Balancing Authority
4	Bulk Electric System
5	N/A
6	N/A
7	N/A
8	N/A
9	N/A
10	N/A
11	Interchange Distribution Calculator
12	N/A
13	N/A
14	N/A
15	N/A
16	N/A

List of all other defined terms that are included in the Interconnection definition narrative:

Glossary: None

ROP: Bulk Power System; Reliable Operation; Facilities

III. DRAFTING TEAM ANALYSIS AND ASSESSMENT

Explanation of differences in definition narratives: The ROP definition provides a description of what an interconnection is conceptually, and the criteria for use in identifying one. The Glossary definition, on the other hand, "defines" the term by applying the ROP definition and identifying the specific geographical areas that meet the criteria outlined in the ROP definition. The difference in these two definitions would be similar to defining the term "Federal Holiday" by listing all eleven federal holidays in the United States (*e.g.*, New Year's Day, MLK Jr. Day, Inauguration Day, etc.) as opposed to defining the term by describing what constitutes a "Federal Holiday" in the abstract (*i.e.*, "an authorized holiday which has been recognized by the US government and on which non-essential federal government offices are closed").

How/why the terms may be applied differently as a result of the differences: The ROP definition is broader than the Glossary because it provides a description of what constitutes an interconnection, as opposed to identifying the specific geographical areas in North America that currently constitute an interconnection. Because the Glossary limits application of the definition to the specific interconnections identified therein, it could be perceived as intended to be more limiting and/or intentionally different than the ROP definition.

Proposed revision(s). The SDT proposes revisions to both the Glossary and ROP definition in order to align the two terms and maintain consistency with the Federal Power Act. Redlines of both definitions are provided below.

Redline of Glossary definition:

A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Redline of ROP definition:

a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++ When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.**

Justification for decision: The ROP definition tracks the Federal Power Act (note it is marked with ++ indicating such). In order to align the two definitions, without losing the clarity provided by the FERC-approved Glossary definition, which specifically identifies the current Interconnections in North America, the SDT is proposing to combine the two definitions. However, because the recently FERC-approved Glossary definition is not effective until July 1, 2016, the SDT is proposing that the alignment revisions do not take effect until July 1, 2016, at the earliest.

Term 46: Special Protection System

Glossary Definition (differences in definition narrative indicated in red)	ROP, Appendix 2 Definition (differences in definition narrative indicated in red)	SDT proposed revisions
An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage Load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).**	The SDT is not proposing any alignment revisions at this time. This is because the Project 2010-5.3 drafting team work is still underway and the team may propose changes to this definition. Once the Project 2010-5.3 team finalizes its work, then it will be appropriate to make any necessary alignment changes to the definition of Special Protection System.

Part V: Group 3 recommendations

There are a total of twenty-two (22) Group 3 cross-over terms:

Term 2: Balancing Authority
Term 3: Balancing Authority Area
Term 4: Blackstart Resource
Term 7: Cascading
Term 13: Distribution Provider
Term 14: Element
Term 16: Flowgate
Term 24: Interconnected Operations Service
Term 28: Load Serving Entity
Term 31: Planning Authority
Term 33: Point of Receipt
Term 36: Reactive Power
Term 37: Real Power
Term 38: Reliability Coordinator
Term 41: Reliable Operation
Term 42: Reserve Sharing Group
Term 43: Resource Planner
Term 49: Transmission Customer
Term 50: Transmission Operator
Term 51: Transmission Owner
Term 52: Transmission Planner
Term 54: Transmission Service Provider

The SDT is recommending revisions to all twenty-two (22) of the Group 3 cross-over terms. Below is an overview of the SDT research, assessment, proposed revision(s), and justification for each of the recommendations.

#	Term	Glossary (differences in definition narrative indicated in red)	ROP, Appendix 2 (differences in definition narrative indicated in red)	SDT proposed revisions
2	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.	the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**	The SDT is recommending changes to the ROP definition to align with the Glossary. Specifically, the ROP definition uses the defined term for "Load" whereas the Glossary does not. Due to the manner in which the term "Load" is used in the definition, it is not proper to use the defined term. This is because the current ROP definition of Load is, "an end-user device or customer that receives power from the electric system." In the definition narrative of Balancing Authority, use of the word load is not intended to mean an end-user device or customer. Instead, as used in the definition narrative, the term load is actually referring to the ability to maintain demand, or sufficient levels of generation to meet demand. Essentially, it is addressing a measure of energy available to meet the current demand. Additionally, during the course of its work on this project, the SDT reviewed and assessed the quality and correctness of the definition of "Balancing Authority." The SDT believes the current definition is unclear and could be improved by a few minor changes. Specifically, use or application of the term "load-interchange-generation" contained in the definition narrative is unclear. As a result, will draft a SAR proposing to revise the definition of Balancing Authority in order to address this issue. Redline of ROP definition: the responsible entity that integrates resource plans ahead of time, maintains ~~Load~~load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**
3	Balancing Authority Area	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.	the collection of generation, transmission, and Loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains Load-resource balance within this area.**	The SDT is recommending changes to the ROP definition to align with the Glossary. Specifically, the ROP definition uses the defined term for "Load" whereas the Glossary does not. Due to the manner in which the term "Load" is used in the definition, it is not proper to use the defined term. This is because the current ROP definition of Load is, "an end-user device or customer that receives power from the electric system." In the definition narrative of Balancing Authority Area, use of the word load is not intended to mean an end-user device or customer. Instead, as used in the definition narrative, the term load is actually referring to the ability to maintain demand, or sufficient levels of generation to meet demand. Essentially, it is addressing a measure of energy available to meet the current demand. Redline of ROP definition: the collection of generation, transmission, and ~~Loads~~ loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains ~~Load~~load-resource balance within this area.**

4	Blackstart Resource	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.	a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the terms "Real Power" and "Reactive Power" because they are defined terms in the Glossary and their usage in this definition narrative is intended to have the meaning of the defined terms. Redline of Glossary term: A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for ~~real~~ Real and ~~reactive~~ Reactive ~~power~~ Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
7	Cascading	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.	the uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the terms "System" and "Elements" because they are defined terms in the Glossary and their usage in this definition narrative is intended to have the meaning of the defined terms. Redline of Glossary term: The uncontrolled successive loss of ~~system~~ System ~~elements~~ Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
13	Distribution Provider	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.	the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to remove the capitalization from the term "Distribution" because it is not a defined term in Glossary (or the ROP). Redline of Glossary term: Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the ~~Distribution~~ distribution function at any voltage.

14	Element	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.	any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Element" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An ~~element~~ Element may be comprised of one or more components.
16	Flowgate	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.	1.) A portion of the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.**	The SDT is recommending the following changes: (1) Revise the ROP definition to capitalize the word "Transmission." (2) Add the definition of "Transmission" to the ROP. The term is used (and capitalized) in other ROP definition narratives (see, for example, definition of Bulk Electric System). It is appropriate to capitalize it in this particular narrative because its usage in this definition narrative is intended to have the meaning of the defined term. Additionally, as part of the work for this project, the SDT will develop a set of recommendations regarding improvements to the current ROP and Glossary resources. One of the recommendations will be to conduct a comprehensive review of both the ROP and Glossary to identify all instances where a defined term is used, but it is not capitalized (to indicate applicability or use of the definition). The SDT will recommend that for each occurrence of the term, an assessment is conducted to determine whether the term is intended to have the defined meaning; and in the event it is, then the appropriate revisions should be made. Redline of ROP term: 1.) A portion of the ~~transmission~~ Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.** Add new defined term ("Transmission") to the ROP: "Transmission" means an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.**

24	Interconnected Operations Service	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.	a service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the terms "Transmission Services" and "Reliable Operation" because they are defined terms in the Glossary and their usage in this definition narrative is intended to have the meaning of the defined terms. Redline of Glossary term: A service (exclusive of basic energy and ~~transmission~~ Transmission ~~services~~Services) that is required to support the ~~reliable~~ Reliable ~~operation~~ Operation of interconnected Bulk Electric Systems.
28	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.	an entity that secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Transmission Service" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: Secures energy and ~~transmission~~ Transmission ~~service~~ Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
31	Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.	the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the terms "Facilities" and "Protection Systems" because they are defined terms in the Glossary and their usage in this definition narrative is intended to have the meaning of the defined terms. Redline of Glossary term: The responsible entity that coordinates and integrates transmission ~~facility~~ Facilities and service plans, resource plans, and ~~protection~~ Protection ~~systems~~Systems.
33	Point of Receipt	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.	a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to remove the capitalization from the term "Generator" because it is not a defined term in Glossary or the ROP. Also, because the proposed revisions to the Glossary term will result in alignment of the two definition narratives, the SDT is recommending that a double asterisk (**) is added to the ROP definition.

				Redline of Glossary term: A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a ~~Generator~~ generator delivers its output. Redline of ROP term: a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.**
36	Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).	the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Power" because "Reactive Power" is a defined term and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive ~~power~~ Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive ~~power~~ Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
37	Real Power	The portion of electricity that supplies energy to the load.	the portion of electricity that supplies energy to the Load.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "load" in the Glossary because it is a defined term and its usage in this definition narrative is intended to have the meaning of the defined term. In the definition narrative of Real Power, use of the word load is intended to mean an end-use device or customer. Redline of Glossary definition: The portion of electricity that supplies energy to the ~~load~~Load.

38	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.	the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Reliable Operation" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The entity that is the highest level of authority who is responsible for the ~~reliable~~ Reliable ~~operation~~ Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
41	Reliable Operation	Operating the elements of the bulk-power system [Bulk-Power System~~]~~ within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.	operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.++	The SDT is recommending changes to capitalization in the ROP definition to align with the Glossary and the Federal Power Act. Specifically, the SDT is proposing to remove capitalization of the terms "Elements," "Bulk Power System" "Cascading," and "Cyber Security incident," in order for the definition to remain consistent with the language in the Federal Power Act. Additionally, for both definitions, the SDT is recommending the addition of an explanatory sentence to clarify why defined terms contained in the definition narrative are not capitalized. Redline of Glossary term: Operating the elements of the bulk-power system [Bulk~~-~~ Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements. (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.) Redline of ROP term: operating the ~~Elements~~ elements of the bulk-power system [Bulk Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or ~~Cascading~~ cascading failures of such system will not occur as a result of a sudden disturbance, including a ~~Cyber Security Incident~~ cybersecurity incident, or unanticipated failure of system ~~Elements~~elements~~.~~++ (In

				order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)
42	Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.	a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g. ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**	The SDT is recommending changes to both the Glossary and ROP definitions. Specifically, the SDT is proposing to revise the Glossary definition by removing the capitalization for the terms "Disturbance Control Performance" and "Area" because these are not defined terms. (Note that Disturbance Control Standard and Disturbance are both defined terms). Also, in the ROP definition, the SDT is proposing removal of the unnecessary commas to align with the Glossary definition. Redline of Glossary term: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (*e.g.*, ten minutes). If the transaction is ramped in quicker (*e.g.*, between zero and ten minutes) then, for the purposes of ~~Disturbance~~ disturbance ~~Control~~ control ~~Performance~~performance, the ~~Areas~~ areas become a Reserve Sharing Group. Redline of ROP term: a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (*e.g.*~~,~~ ten minutes). If the transaction is ramped in quicker~~,~~ (*e.g.*, between zero and ten minutes)~~,~~ then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**
43	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.	the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to remove the capitalization from the term "Area" because it is not a defined term in Glossary or the ROP.

				Redline of Glossary term: The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority ~~Area~~area.
49	Transmission Customer	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.	1. any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. 2. Any of the following ~~responsible~~ entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.**	The SDT is recommending the following changes: (1) Revise the Glossary definition to capitalize the term "Transmission Service" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. (2) Remove the word "responsible" to align with the ROP definition. The word "responsible" was originally included in the ROP definition, but was recently removed by the Risk-Based Registration project. The Glossary should be updated to reflect these recent changes. Redline of Glossary term: 1. Any eligible customer (or its designated agent) that can or does execute a ~~transmission~~ Transmission ~~service~~ Service agreement or can or does receive ~~transmission~~ Transmission ~~service~~Service. 2. Any of the following ~~responsible~~ entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
50	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.	the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Facilities" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission ~~facilities~~Facilities.
51	Transmission Owner	The entity that owns and maintains transmission facilities.	the entity that owns and maintains transmission Facilities.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Facilities" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The entity that owns and maintains transmission ~~facilities~~Facilities.

52	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.	the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to remove the capitalization from the term "Area" because it is not a defined term in Glossary or the ROP. Redline of Glossary term: The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority ~~Area~~area.
54	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.	the entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Transmission Service" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~transmission~~ Transmission ~~service~~ Service agreements.

Part VI: Group 4 recommendations

There are a total of three (3) Group 4 cross-over terms:

Term 20: Interchange Authority

Term 27: Load

Term 34: Protection System

The SDT is recommending revisions to all of the Group 4 cross-over terms. Below is an overview of the SDT research, assessment, proposed revision(s), and justification for each of the recommendations.

Term 20: Interchange Authority

Glossary (differences indicated in red)	ROP, Appendix 2 (differences indicated in red)	SDT proposed revisions
The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.	The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communications of Interchange information for reliability assessment purposes.**	The SDT is recommending errata changes to both the Glossary and ROP definitions, as follows: (1) For the Glossary, add the word "the" to align with the ROP definition. (2) For the ROP, remove the "s" from "communications" to align with the Glossary definition. Redline of Glossary term: The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes. Redline of ROP term: The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication~~s~~ of Interchange information for reliability assessment purposes.**

Term 27: Load

Glossary (differences indicated in red)	ROP, Appendix 2 (differences indicated in red)	SDT proposed revisions
An end-use device or customer that receives power from the electric system.	an end-user device or customer that receives power from the electric system.**	The SDT is recommending an errata change to the ROP definition to align with the Glossary. Specifically, the SDT is proposing to remove the letter "r" from the word "user" in the ROP definition because it was inadvertently included when the definition was added to Appendix 2 of the ROP. On January 26, 2012, NERC filed a petition for approval of various revisions to the ROP, including the addition of new terms to Appendix 2. See, NERC petition. The definition of "Load" was adopted from the Glossary, and marked with a double asterisk (**) to indicate as such. However, the definition included in the NERC petition added the letter "r" to the word "use" which did not (and does not currently) exist in the Glossary definition. For these reasons, the SDT is recommending removal of the "r" from the word "user" in the ROP definition in order to align the Glossary and ROP narratives. Redline of ROP term: an end-user~~r~~ device or customer that receives power from the electric system.**

		Additionally, the SDT notes that during the course of its work on this project, the team reviewed and assessed the quality and correctness of the definition of "Load." The SDT believes the current definition is deficient and could be improved in quality and content. As a result, will draft a SAR proposing to revise the definition in order to address the issues identified by the SDT.

Term 34: Protection System

Glossary (differences indicated in red)	ROP, Appendix 2 (differences indicated in red)	SDT proposed revisions
• Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting device.	protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**	The SDT is recommending an errata change to the ROP definition to align with the Glossary. Specifically, the SDT is proposing to add the word "station" to qualify the Protection System component batteries because it was inadvertently left out of the ROP definition narrative. In 2013, FERC approved the currently effective Glossary definition, which included the qualifier of "station" to the battery term in the definition narrative. However, when the term was adopted in Appendix 2 of the ROP, the qualifier "station" was not included in the definition narrative. Redline of ROP definition: protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**

ATTACHMENT 1
COMPLETE LIST OF CROSS-OVER TERMS

GROUP 1: Content/substance differences

Term 1: Adjacent Balancing Authority
Term 6: Bulk Power System
Term 17: Generator Operator
Term 18: Generator Owner
Term 29: Net Energy for Load or NEL
Term 40: Reliability Standard
Term 44: Sink Balancing Authority
Term 45: Source Balancing Authority
Term 48: System Operating Limit

GROUP 2: Definitions currently in flux

Term 8: Critical Assets
Term 9: Critical Cyber Assets
Term 10: Cyber Assets
Term 11: Cyber Security Incident
Term 25: Interconnection
Term 46: Special Protection System

GROUP 3: Capitalization differences

Term 2: Balancing Authority
Term 3: Balancing Authority Area
Term 4: Blackstart Resource
Term 7: Cascading
Term 13: Distribution Provider
Term 14: Element
Term 16: Flowgate
Term 24: Interconnected Operations Service
Term 28: Load Serving Entity
Term 31: Planning Authority
Term 33: Point of Receipt
Term 36: Reactive Power
Term 37: Real Power
Term 38: Reliability Coordinator
Term 41: Reliable Operation
Term 42: Reserve Sharing Group
Term 43: Resource Planner
Term 49: Transmission Customer
Term 50: Transmission Operator
Term 51: Transmission Owner
Term 52: Transmission Planner
Term 54: Transmission Service Provider

GROUP 4: Miscellaneous/Errata

Term 20: Interchange Authority
Term 27: Load
Term 34: Protection System

#	Term	Glossary (differences indicated in red)	ROP, Appendix 2 (differences indicated in red)	GROUP
1	Adjacent Balancing Authority	A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.	a Balancing Authority Area that is interconnected to another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**	GROUP 1
2	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.	the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**	GROUP 3
3	Balancing Authority Area	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.	the collection of generation, transmission, and Loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains Load-resource balance within this area.**	GROUP 3
4	Blackstart Resource	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.	a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.**	GROUP 3
5	Bulk Electric System or BES	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy…	unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy…**	
6	Bulk Power System	Bulk-Power System: A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.	"Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.	GROUP 1
7	Cascading	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.	the uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.**	GROUP 3

8	Critical Assets	Inactive beginning 3/31/2016: Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.**	GROUP 2
9	Critical Cyber Assets	Inactive beginning 3/31/2016: Cyber Assets essential to the reliable operation of Critical Assets.	Cyber Assets critical to the reliable operation of Critical Assets.**	GROUP 2
10	Cyber Assets	Inactive beginning 3/31/16: Programmable electronic devices and communication networks including hardware, software, and data. Effective beginning 4/1/2016: Programmable electronic devices, including the hardware, software, and data in those devices.	programmable electronic devices and communication networks including hardware, software, and data.** programmable electronic devices and communication networks including hardware, software, and data.**	GROUP 2
11	Cyber Security Incident	Inactive beginning 3/31/2016: Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset. Effective beginning 4/1/2016: A malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.	"Cyber Security Incident" means any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.++	GROUP 2
12	Distribution Factor	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).	the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).**	
13	Distribution Provider	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.	the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**	GROUP 3

14	Element	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.	any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.**	GROUP 2
15	Facility	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)	a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)**	
16	Flowgate	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.	1.) A portion of the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.**	GROUP 3
17	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	the entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.**	GROUP 1
18	Generator Owner	Entity that owns and maintains generating units.	an entity that owns and maintains generating Facility(ies).**	GROUP 1
19	Interchange	Energy transfers that cross Balancing Authority boundaries.	energy transfers that cross Balancing Authority boundaries.**	
20	Interchange Authority	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.	the responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communications of Interchange information for reliability assessment purposes.**	GROUP 4
21	Interchange Distribution Calculator	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.	the mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.**	
22	Interchange Schedule	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.	an agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.**	
23	Interchange Transaction	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.	an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.**	

24	Interconnected Operations Service	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.	a service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.**	GROUP 3
25	Interconnection	Inactive beginning 6/30/16: When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT. Effective beginning 7/1/16: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.	a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++	GROUP 2
26	Interconnection Reliability Operating Limit	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.	a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.**	
27	Load	An end-use device or customer that receives power from the electric system.	an end-user device or customer that receives power from the electric system.**	GROUP 4
28	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.	an entity that secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.**	GROUP 3
29	Net Energy for Load or NEL	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.	net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.	GROUP 1
30	Open Access Transmission Tariff	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.	an electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.**	
31	Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.	the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.**	GROUP 3
32	Point of Delivery	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.	a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.**	
33	Point of Receipt	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.	a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.	GROUP 3

34	Protection System	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.	protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**	GROUP 4
35	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.	the entity that purchases, or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.**	
36	Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).	the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).**	GROUP 3
37	Real Power	The portion of electricity that supplies energy to the load.	the portion of electricity that supplies energy to the Load.**	GROUP 3
38	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.	the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.**	GROUP 3
39	Reliability Coordinator Area	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.	the collection of generation, transmission and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.**	

40	Reliability Standard	A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.	a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.	GROUP 1
41	Reliable Operation	Operating the elements of the bulk-power system [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.	operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.++	GROUP 3
42	Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.	a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g. ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**	GROUP 3
43	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.	the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.**	GROUP 3
44	Sink Balancing Authority	The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.	the Balancing Authority in which the Load (sink) is located for an Interchange Transaction.**	GROUP 1
45	Source Balancing Authority	The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.	the Balancing Authority in which the generation (source) is located for an Interchange Transaction.**	GROUP 1
46	Special Protection System	An automatic protection system designed to detect abnormal or predetermined system conditions, and	an automatic protection system designed to detect abnormal or predetermined system conditions, and	GROUP 2

		take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage Load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).**	
47	System	A combination of generation, transmission, and distribution components.	a combination of generation, transmission and distribution components.**	
48	System Operating Limit	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)	the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.**	GROUP 1
49	Transmission Customer	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.	1. any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. 2. Any of the following ~~responsible~~ entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.**	GROUP 3
50	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.	the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.**	GROUP 3
51	Transmission Owner	The entity that owns and maintains transmission facilities.	the entity that owns and maintains transmission Facilities.**	GROUP 3
52	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.	the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.**	GROUP 3
53	Transmission Service	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.	services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.**	

54	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.	the entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.**	GROUP 3
55	Wide Area	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.	the entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.**	

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ATTACHMENT 2
COMPLETE LIST OF CROSS-OVER TERMS WITH PROPOSED REVISIONS

GROUP 1: Content/substance differences

Term 1: Adjacent Balancing Authority
Term 6: Bulk Power System
Term 17: Generator Operator
Term 18: Generator Owner
Term 29: Net Energy for Load or NEL
Term 40: Reliability Standard
Term 44: Sink Balancing Authority
Term 45: Source Balancing Authority
Term 48: System Operating Limit

GROUP 2: Definitions currently in flux

Term 8: Critical Assets
Term 9: Critical Cyber Assets
Term 10: Cyber Assets
Term 11: Cyber Security Incident
Term 25: Interconnection
Term 46: Special Protection System

GROUP 3: Capitalization differences

Term 2: Balancing Authority
Term 3: Balancing Authority Area
Term 4: Blackstart Resource
Term 7: Cascading
Term 13: Distribution Provider
Term 14: Element
Term 16: Flowgate
Term 24: Interconnected Operations Service
Term 28: Load Serving Entity
Term 31: Planning Authority
Term 33: Point of Receipt
Term 36: Reactive Power
Term 37: Real Power
Term 38: Reliability Coordinator
Term 41: Reliable Operation
Term 42: Reserve Sharing Group
Term 43: Resource Planner
Term 49: Transmission Customer
Term 50: Transmission Operator
Term 51: Transmission Owner
Term 52: Transmission Planner
Term 54: Transmission Service Provider

GROUP 4: Miscellaneous/Errata

Term 20: Interchange Authority
Term 27: Load
Term 34: Protection System

#	Cross-Over Term	Glossary (differences indicated in red)	ROP, Appendix 2 (differences indicated in red)	SDT Proposed Revisions
1	Adjacent Balancing Authority	A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.	a Balancing Authority Area that is interconnected to another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**	The SDT is proposing to revise the ROP definition to align with the Glossary. Redline of ROP definition: a Balancing Authority ~~Area~~ whose Balancing Authority Area ~~that~~ is interconnected ~~with to~~ another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**
2	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.	the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**	The SDT is recommending changes to the ROP definition to align with the Glossary. Specifically, the ROP definition uses the defined term for "Load" whereas the Glossary does not. Due to the manner in which the term "Load" is used in the definition, it is not proper to use the defined term. This is because the current ROP definition of Load is, "an end-user device or customer that receives power from the electric system." In the definition narrative of Balancing Authority, use of the word load is not intended to mean an end-user device or customer. Instead, as used in the definition narrative, the term load is actually referring to the ability to maintain demand, or sufficient levels of generation to meet demand. Essentially, it is addressing a measure of energy available to meet the current demand. Additionally, during the course of its work on this project, the SDT reviewed and assessed the quality and correctness of the definition of "Balancing Authority." The SDT believes the current definition is unclear and could be improved by a few minor changes. Specifically, use or application of the term "load-interchange-generation" contained in the definition narrative is unclear. As a result, will draft a SAR proposing to revise the definition of Balancing Authority in order to address this issue. Redline of ROP definition: the responsible entity that integrates resource plans ahead of time, maintains ~~Load~~load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**

3	Balancing Authority Area	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.	the collection of generation, transmission, and Loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains Load-resource balance within this area.**	The SDT is recommending changes to the ROP definition to align with the Glossary. Specifically, the ROP definition uses the defined term for "Load" whereas the Glossary does not. Due to the manner in which the term "Load" is used in the definition, it is not proper to use the defined term. This is because the current ROP definition of Load is, "an end-user device or customer that receives power from the electric system." In the definition narrative of Balancing Authority Area, use of the word load is not intended to mean an end-user device or customer. Instead, as used in the definition narrative, the term load is actually referring to the ability to maintain demand, or sufficient levels of generation to meet demand. Essentially, it is addressing a measure of energy available to meet the current demand. Redline of ROP definition: the collection of generation, transmission, and ~~Loads~~ loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains ~~Load~~load-resource balance within this area.**
4	Blackstart Resource	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.	a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the terms "Real Power" and "Reactive Power" because they are defined terms in the Glossary and their usage in this definition narrative is intended to have the meaning of the defined terms. Redline of Glossary term: A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for ~~real~~ Real and ~~reactive~~ Reactive ~~power~~ Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
5	Bulk Electric System or BES	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This	unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This	Definitions are aligned.

		does not include facilities used in the local distribution of electric energy…	does not include facilities used in the local distribution of electric energy…**	
6	Bulk Power System	Bulk-Power System: A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.	"Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.	The SDT is proposing to revise both definitions as follows: Redline of Glossary definition: Bulk- Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.) Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning. Redline of ROP, Appendix 2 definition: Bulk Power System" means, depending on the context: (i) (A) ~~Facilities~~ facilities and control systems necessary for operating an interconnected electric energy ~~supply and~~ transmission network (or any portion thereof);~~,~~ and (B) electric energy from generation~~g~~ facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.) ~~-~~Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.
7	Cascading	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be	the uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be	The SDT is recommending changes to the Glossary definition to align with the ROP. ~~-~~Specifically, the SDT is proposing to capitalize the terms "System" and "Elements" because they are defined terms in the

		restrained from sequentially spreading beyond an area predetermined by studies.	restrained from sequentially spreading beyond an area predetermined by studies.**	Glossary and their usage in this definition narrative is intended to have the meaning of the defined terms. Redline of Glossary term: The uncontrolled successive loss of ~~system~~ System ~~elements~~ Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
8	Critical Assets	Inactive beginning 3/31/2016: Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.**	The SDT is not proposing revisions to the cross-over terms at this time. This is because the changes that would be necessary to align the terms would necessitate a large number of other changes that are outside the scope of the SAR for this project. The SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.
9	Critical Cyber Assets	Inactive beginning 3/31/2016: Cyber Assets essential to the reliable operation of Critical Assets.	Cyber Assets critical to the reliable operation of Critical Assets.**	The SDT is not proposing revisions to the cross-over terms at this time. This is because the changes that would be necessary to align the terms would necessitate a large number of other changes that are outside the scope of the SAR for this project. The SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.

10	Cyber Assets	Inactive beginning 3/31/16: Programmable electronic devices and communication networks including hardware, software, and data. Effective beginning 4/1/2016: Programmable electronic devices, including the hardware, software, and data in those devices.	programmable electronic devices and communication networks including hardware, software, and data.** programmable electronic devices and communication networks including hardware, software, and data.**	The SDT is not proposing revisions to the cross-over terms at this time. This is because the changes that would be necessary to align the terms would necessitate a large number of other changes that are outside the scope of the SAR for this project. The SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.
11	Cyber Security Incident	Inactive beginning 3/31/2016: Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset. Effective beginning 4/1/2016: A malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.	"Cyber Security Incident" means any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.++	The SDT is not proposing revisions to the cross-over terms at this time. This is because the changes that would be necessary to align the terms would necessitate a large number of other changes that are outside the scope of the SAR for this project. The SDT will submit a SAR to address the alignment of terms for all CIP-related definitions. The proposed SAR will include alignment of the defined terms to incorporate the changes to the ROP definitions made through the Version 5 revisions, and also any revisions necessary to provisions of the ROP as a result of proposed changes to the ROP defined terms contained in Appendix 2. The SAR will propose that members of the Project 2008-06 SDT are involved with the revisions to the ROP.
12	Distribution Factor	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).	the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).**	Definitions are aligned.

13	Distribution Provider	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.	the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to remove the capitalization from the term "Distribution" because it is not a defined term in Glossary (or the ROP). Redline of Glossary term: Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the ~~Distribution~~ distribution function at any voltage.
14	Element	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.	any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Element" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An ~~element~~ Element may be comprised of one or more components.
15	Facility	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)	a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)**	Definitions are aligned.
16	Flowgate	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities,	1.) A portion of the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities,	The SDT is recommending the following changes: (1) Revise the ROP definition to capitalize the word "Transmission." (2) Add the definition of "Transmission" to the ROP. The term is used (and capitalized) in other ROP definition narratives (see, for example, definition of Bulk Electric System). It is appropriate to capitalize it in this particular narrative because

		used to analyze the impact of power flows upon the Bulk Electric System.	used to analyze the impact of power flows upon the Bulk Electric System.**	its usage in this definition narrative is intended to have the meaning of the defined term. Additionally, as part of the work for this project, the SDT will develop a set of recommendations regarding improvements to the current ROP and Glossary resources. One of the recommendations will be to conduct a comprehensive review of both the ROP and Glossary to identify all instances where a defined term is used, but it is not capitalized (to indicate applicability or use of the definition). The SDT will recommend that for each occurrence of the term, an assessment is conducted to determine whether the term is intended to have the defined meaning; and in the event it is, then the appropriate revisions should be made. Redline of ROP term: 1.) A portion of the ~~transmission~~ Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.** Add new defined term ("Transmission") to the ROP: "Transmission" means an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.**
17	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	the entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.**	The SDT is proposing to revise the Glossary definition to align with the ROP. Redline of Glossary definition: The entity that operates generating Facility(ies) ~~unit(s)~~ and performs the functions of supplying energy and Interconnected Operations Services.

				Additionally, the SDT notes that during the course of its work on this project, the team reviewed and assessed the quality of the definition of "Facility." The SDT believes the clarity and content of the current definition could be improved. As a result, the SDT will draft a SAR proposing to revise the definition in order to address the issues identified by the SDT.
18	Generator Owner	Entity that owns and maintains generating units.	an entity that owns and maintains generating Facility(ies).**	The SDT is proposing to revise the Glossary definition to align with the ROP. Redline of Glossary definition: Entity that owns and maintains generating Facility(ies)~~units~~. Additionally, the SDT notes that during the course of its work on this project, the team reviewed and assessed the quality of the definition of "Facility." The SDT believes the clarity and content of the current definition could be improved. As a result, the SDT will draft a SAR proposing to revise the definition in order to address the issues identified by the SDT.
19	Interchange	Energy transfers that cross Balancing Authority boundaries.	energy transfers that cross Balancing Authority boundaries.**	Definitions are aligned.
20	Interchange Authority	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.	the responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communications of Interchange information for reliability assessment purposes.**	The SDT is recommending errata changes to both the Glossary and ROP definitions, as follows: (1) For the Glossary, add the word "the" to align with the ROP definition. (2) For the ROP, remove the "s" from "communications" to align with the Glossary definition. Redline of Glossary term: The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.

				Redline of ROP term: The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communications of Interchange information for reliability assessment purposes.**
21	Interchange Distribution Calculator	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.	the mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.**	Definitions are aligned.
22	Interchange Schedule	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.	an agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.**	Definitions are aligned.
23	Interchange Transaction	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.	an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.**	Definitions are aligned.
24	Interconnected Operations Service	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.	a service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the terms "Transmission Services" and "Reliable Operation" because they are defined terms in the Glossary and their usage in this definition narrative is intended to have the meaning of the defined terms. Redline of Glossary term: A service (exclusive of basic energy and ~~transmission~~ Transmission ~~services~~Services) that is required to support the ~~reliable~~ Reliable ~~operation~~ Operation of interconnected Bulk Electric Systems.

25	Interconnection	Inactive beginning 6/30/16: When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT. Effective beginning 7/1/16: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.	a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++	The SDT is proposing to revise both the Glossary and ROP definitions (effective no earlier than 07/01/16), as follows: Redline of Glossary definition: A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec. Redline of ROP definition: a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++ When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.**
26	Interconnection Reliability Operating Limit	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.	a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.**	Definitions are aligned.
27	Load	An end-use device or customer that receives power from the electric system.	an end-user device or customer that receives power from the electric system.**	The SDT is recommending an errata change to the ROP definition to align with the Glossary. Specifically, the SDT is proposing to remove the letter "r" from the word "user" in the ROP definition because it was inadvertently included when the definition was added to Appendix 2 of the ROP. On January 26, 2012, NERC filed a petition for approval of various revisions to the ROP, including the addition of new terms to Appendix 2. (*See*, NERC petition). The definition of "Load" was adopted from the Glossary, and marked with a double asterisk (**) to indicate as such. However, the definition included in the NERC petition added the letter "r" to the word "use" which did not (and does not currently) exist in the Glossary definition. For these reasons, the SDT is recommending

				removal of the "r" from the word "user" in the ROP definition in order to align the Glossary and ROP narratives. Redline of ROP term: an end-user device or customer that receives power from the electric system.** Additionally, the SDT notes that during the course of its work on this project, the team reviewed and assessed the quality and correctness of the definition of "Load." The SDT believes the current definition is deficient and could be improved in quality and content. As a result, will draft a SAR proposing to revise the definition in order to address the issues identified by the SDT.
28	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.	an entity that secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Transmission Service" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: Secures energy and ~~transmission~~ Transmission ~~service~~ Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
29	Net Energy for Load or NEL	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.	net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.	No changes to either ROP or Glossary. The SDT recommends the terms remain unaligned. The differences in the definition narratives are appropriate given the differing uses of the term within the Glossary and ROP.

30	Open Access Transmission Tariff	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.	an electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.**	Definitions are aligned.
31	Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.	the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the terms "Facilities" and "Protection Systems" because they are defined terms in the Glossary and their usage in this definition narrative is intended to have the meaning of the defined terms. Redline of Glossary term: The responsible entity that coordinates and integrates transmission ~~facility~~ Facilities and service plans, resource plans, and ~~protection~~ Protection ~~systems~~Systems.
32	Point of Delivery	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.	a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.**	Definitions are aligned.
33	Point of Receipt	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.	a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to remove the capitalization from the term "Generator" because it is not a defined term in Glossary or the ROP. Also, because the proposed revisions to the Glossary term will result in alignment of the two definition narratives, the SDT is recommending that a double asterisk (**) is added to the ROP definition. Redline of Glossary term: A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a ~~Generator~~ generator delivers its output.

				Redline of ROP term: a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.**
34	Protection System	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.	protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**	The SDT is recommending an errata change to the ROP definition to align with the Glossary. Specifically, the SDT is proposing to add the word "station" to qualify the Protection System component batteries because it was inadvertently left out of the ROP definition narrative. In 2013, FERC approved the currently effective Glossary definition, which included the qualifier of "station" to the battery term in the definition narrative. However, when the term was adopted in Appendix 2 of the ROP, the qualifier "station" was not included in the definition narrative. Redline of ROP definition: protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**
35	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.	the entity that purchases, or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.**	Definitions are aligned.
36	Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It	the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Power" because "Reactive Power" is a defined term and its usage in this definition narrative is intended to have the meaning of the defined term.

		also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).	also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).**	Redline of Glossary term: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive ~~power~~ Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive ~~power~~ Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
37	Real Power	The portion of electricity that supplies energy to the load.	the portion of electricity that supplies energy to the Load.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "load" in the Glossary because it is a defined term and its usage in this definition narrative is intended to have the meaning of the defined term. In the definition narrative of Real Power, use of the word load is intended to mean an end-use device or customer. Redline of Glossary definition: The portion of electricity that supplies energy to the ~~load~~Load.
38	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.	the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Reliable Operation" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The entity that is the highest level of authority who is responsible for the ~~reliable~~ Reliable ~~operation~~ Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of

				transmission systems beyond any Transmission Operator's vision.
39	Reliability Coordinator Area	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.	the collection of generation, transmission and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.**	Definitions are aligned.
40	Reliability Standard	A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.	a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.	The SDT is proposing revisions to both the Glossary and ROP definitions, as follows: Redline of Glossary definition: A requirement, approved by the United States Federal Energy Regulatory Commission under ~~this~~ Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.) Redline of ROP definition: a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk Power System]. ~~, including without limiting the foregoing,~~ The term includes requirements for the operation of existing bulk-power system [Bulk Power System] ~~Facilities~~facilities, including cyber security protection, and ~~including~~ the design of planned additions or

				modifications to such ~~Facilities~~ facilities to the extent necessary for reliable operation [Reliable Operation] of the bulk-power system [Bulk Power System], but the term does not include any requirement to enlarge ~~Bulk Power System~~ such ~~Facilities~~ facilities or to construct new transmission capacity or generation capacity.++ (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.) In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions. ~~A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.~~
41	Reliable Operation	Operating the elements of the bulk-power system [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.	operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.++	The SDT is recommending changes to capitalization in the ROP definition to align with the Glossary and the Federal Power Act. Specifically, the SDT is proposing to remove capitalization of the terms "Elements," "Bulk Power System" "Cascading," and "Cyber Security incident," in order for the definition to remain consistent with the language in the Federal Power Act. Additionally, for both definitions, the SDT is recommending the addition of an explanatory sentence to clarify why defined terms contained in the definition narrative are not capitalized. Redline of Glossary term: Operating the elements of the bulk-power system [Bulk- Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements. (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)

				Redline of ROP term: operating the ~~Elements~~ elements of the bulk-power system [Bulk Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or ~~Cascading~~ cascading failures of such system will not occur as a result of a sudden disturbance, including a ~~Cyber Security Incident~~ cybersecurity incident, or unanticipated failure of system ~~Elements~~elements.++ (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)
42	Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.	a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g. ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**	The SDT is recommending changes to both the Glossary and ROP definitions. Specifically, the SDT is proposing to revise the Glossary definition by removing the capitalization for the terms "Disturbance Control Performance" and "Area" because these are not defined terms. (Note that Disturbance Control Standard and Disturbance are both defined terms). Also, in the ROP definition, the SDT is proposing removal of the unnecessary commas to align with the Glossary definition. Redline of Glossary term: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (*e.g.*, ten minutes). If the transaction is ramped in quicker (*e.g.*, between zero and ten minutes) then, for the purposes of ~~Disturbance~~ disturbance ~~Control~~ control ~~Performance~~performance, the ~~Areas~~ areas become a Reserve Sharing Group. Redline of ROP term: a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply

				operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (*e.g.*, ten minutes). If the transaction is ramped in quicker, (*e.g.*, between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**
43	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.	the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to remove the capitalization from the term "Area" because it is not a defined term in Glossary or the ROP. Redline of Glossary term: The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority ~~Area~~area.
44	Sink Balancing Authority	The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.	the Balancing Authority in which the Load (sink) is located for an Interchange Transaction.**	The SDT is proposing to revise the ROP definition to align with the Glossary definition. Redline of ROP definition: the Balancing Authority in which the ~~Load~~ load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.**
45	Source Balancing Authority	The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.	the Balancing Authority in which the generation (source) is located for an Interchange Transaction.**	The SDT is proposing to revise the ROP definition to align with the Glossary definition. Redline of ROP definition: the Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.**

46	Special Protection System	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage Load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).**	The SDT is not proposing any alignment revisions at this time. This is because the Project 2010-5.3 drafting team work is still underway and the team may propose changes to this definition. Once the Project 2010-5.3 team finalizes its work, then it will be appropriate to make any necessary alignment changes to the definition of Special Protection System.
47	System	A combination of generation, transmission, and distribution components.	a combination of generation, transmission and distribution components.**	Definitions are aligned.
48	System Operating Limit	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)	the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.**	The SDT is proposing to revise both the Glossary and ROP, as follows: Redline of Glossary definition: The value (such as MW, MVar, ~~A~~amperes, ~~Frequency~~ frequency or ~~Volts~~volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (~~Applicable~~ applicable pre- and post-Contingency ~~equipment~~ Equipment Ratings or ~~facility~~ Facility ~~ratings~~Ratings) • ~~Transient~~ transient ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Stability~~ stability ~~Limits~~limits) • ~~Voltage~~ voltage ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Stability~~stability)

				• ~~System~~ system ~~Voltage~~ voltage ~~Limits~~ limits (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Limits~~limits) Redline of ROP definition: the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • facility ratings (applicable pre- and post-contingency equipment ratings or facility ratings) • transient stability ratings (applicable pre- and post-contingency stability limits) • voltage stability ratings (applicable pre- and post-contingency voltage stability) • system voltage limits (applicable pre- and post-contingency voltage limits)**
49	Transmission Customer	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.	1. any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. 2. Any of the following ~~responsible~~ entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.**	The SDT is recommending the following changes: (1) Revise the Glossary definition to capitalize the term "Transmission Service" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. (2) Remove the word "responsible" to align with the ROP definition. The word "responsible" was originally included in the ROP definition, but was recently removed by the Risk-Based Registration project. The Glossary should be updated to reflect these recent changes. Redline of Glossary term: 1. Any eligible customer (or its designated agent) that can or does execute a ~~transmission~~ Transmission ~~service~~ Service agreement or can or does receive ~~transmission~~ Transmission ~~service~~Service. 2. Any of the following ~~responsible~~ entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

50	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.	the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Facilities" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission ~~facilities~~Facilities.
51	Transmission Owner	The entity that owns and maintains transmission facilities.	the entity that owns and maintains transmission Facilities.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Facilities" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The entity that owns and maintains transmission ~~facilities~~Facilities.
52	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.	the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to remove the capitalization from the term "Area" because it is not a defined term in Glossary or the ROP. Redline of Glossary term: The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority ~~Area~~area.
53	Transmission Service	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.	services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.**	Definitions are aligned.

54	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.	the entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.**	The SDT is recommending changes to the Glossary definition to align with the ROP. Specifically, the SDT is proposing to capitalize the term "Transmission Service" because it is a defined term in the Glossary and its usage in this definition narrative is intended to have the meaning of the defined term. Redline of Glossary term: The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~transmission~~ Transmission ~~service~~ Service agreements.
55	Wide Area	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.	the entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.**	Definitions are aligned.

Proposed Revisions to the Glossary of Terms

Project 2015-04 Alignment of Terms

#	Term	Existing Glossary definition	Redline of Glossary definition
4	Blackstart Resource	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for ~~real~~ Real and ~~reactive~~ Reactive ~~power~~ Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
6	Bulk-Power System	Bulk-Power System: A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.	Bulk~~-~~ Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.) Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.

7	Cascading	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.	The uncontrolled successive loss of ~~system~~ System ~~elements~~ Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
13	Distribution Provider	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the ~~Distribution~~ distribution function at any voltage.
14	Element	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An ~~element~~ Element may be comprised of one or more components.
17	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	The entity that operates generating Facility(ies) ~~unit(s)~~ and performs the functions of supplying energy and Interconnected Operations Services.
18	Generator Owner	Entity that owns and maintains generating units.	Entity that owns and maintains generating Facility(ies)~~units~~.

20	Interchange Authority	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.	The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
24	Interconnected Operations Service	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.	A service (exclusive of basic energy and ~~transmission~~ Transmission ~~services~~Services) that is required to support the ~~reliable~~ Reliable ~~operation~~ Operation of interconnected Bulk Electric Systems.
25	Interconnection	**Effective beginning 7/1/16**: When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.	A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
28	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.	Secures energy and ~~transmission~~ Transmission ~~service~~ Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

31	Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.	The responsible entity that coordinates and integrates transmission ~~facility~~ Facilities and service plans, resource plans, and ~~protection~~ Protection ~~systems~~Systems.
33	Point of Receipt	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a ~~Generator~~ generator delivers its output.
36	Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive ~~power~~ Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive ~~power~~ Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
37	Real Power	The portion of electricity that supplies energy to the load.	The portion of electricity that supplies energy to the ~~load~~Load.
38	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis	The entity that is the highest level of authority who is responsible for the ~~reliable~~ Reliable ~~operation~~ Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis

		and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.	and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
40	Reliability Standard	A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.	A requirement, approved by the United States Federal Energy Regulatory Commission under ~~this~~ Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk- Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk- Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk- Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)
41	Reliable Operation	Operating the elements of the bulk-power system [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.	Operating the elements of the bulk-power system [Bulk- Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements. (In order to remain

			consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)
42	Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (*e.g.*, ten minutes). If the transaction is ramped in quicker (*e.g.*, between zero and ten minutes) then, for the purposes of ~~Disturbance~~ disturbance ~~Control~~ control ~~Performance~~performance, the ~~Areas~~ areas become a Reserve Sharing Group.
43	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority ~~Area~~area.
48	System Operating Limit	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:	The value (such as MW, MVar, ~~A~~amperes, ~~Frequency~~ frequency or ~~Volts~~volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

		• Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)	• Facility Ratings (~~Applicable~~ applicable pre- and post-Contingency ~~equipment~~ Equipment Ratings or ~~facility~~ Facility ~~ratings~~Ratings) • ~~Transient~~ transient ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Stability~~ stability ~~Limits~~limits) • ~~Voltage~~ voltage ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Stability~~stability) • ~~System~~ system ~~Voltage~~ voltage ~~Limits~~ limits (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Limits~~limits)
49	Transmission Customer	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.	1. Any eligible customer (or its designated agent) that can or does execute a ~~transmission~~ Transmission ~~service~~ Service agreement or can or does receive ~~transmission~~ Transmission ~~service~~Service. 2. Any of the following ~~responsible~~ entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
50	Transmission Operator	The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.	The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission ~~facilities~~Facilities.
51	Transmission Owner	The entity that owns and maintains transmission facilities.	The entity that owns and maintains transmission ~~facilities~~Facilities.

52	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority ~~Area~~area.
54	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~transmission~~ Transmission ~~service~~ Service agreements.

Proposed Revisions to Appendix 2 of the Rules of Procedure

Project 2015-04 Alignment of Terms

#	Cross-over Term	Existing Appendix 2, ROP definition	Redline of Appendix 2, ROP definition
1	Adjacent Balancing Authority	a Balancing Authority Area that is interconnected to another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**	a Balancing Authority ~~Area~~ whose Balancing Authority Area ~~that~~ is interconnected with ~~to~~ another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**
2	Balancing Authority	the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**	the responsible entity that integrates resource plans ahead of time, maintains ~~Load~~load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**
3	Balancing Authority Area	the collection of generation, transmission, and Loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains Load-resource balance within this area.**	the collection of generation, transmission, and ~~Loads~~ loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains ~~Load~~load-resource balance within this area.**
6	Bulk Power System	"Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof),	Bulk Power System" means, depending on the context: (i) (A) ~~Facilities~~ facilities and control systems necessary for operating an interconnected electric energy ~~supply and~~ transmission network (or any portion thereof)~~;~~ and

		and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.	(B) electric energy from generation~~g~~ facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++].(In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.)~~-~~Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.
16	Flowgate	1.) A portion of the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.**	1.) A portion of the ~~transmission~~ Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.** **Add "Transmission" as a new defined term to the ROP:** "Transmission" means an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.**
20	Interchange Authority	the responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communications of Interchange information for reliability assessment purposes.**	The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication~~s~~ of Interchange information for reliability assessment purposes.**

25	Interconnection	a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++	a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++ When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.**
27	Load	an end-user device or customer that receives power from the electric system.**	an end-use~~r~~ device or customer that receives power from the electric system.**
33	Point of Receipt	a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.	a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.**
34	Protection System	protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**	protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**

40	Reliability Standard	a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.	a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk Power System]. ~~, including without limiting the foregoing,~~ The term includes requirements for the operation of existing bulk-power system [Bulk Power System] ~~Facilities~~facilities, including cyber-security protection, and ~~including~~ the design of planned additions or modifications to such ~~Facilities~~ facilities to the extent necessary for reliable operation [Reliable Operation] of the bulk-power system [Bulk Power System], but the term does not include any requirement to enlarge ~~Bulk Power System~~ such ~~Facilities~~ facilities or to construct new transmission capacity or generation capacity.++ (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.) In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions. ~~A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.~~
41	Reliable Operation	operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden	operating the ~~Elements~~ elements of the bulk-power system [Bulk Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or ~~Cascading~~ cascading failures of such system will not occur as a result of a sudden disturbance, including a ~~Cyber Security Incident~~ cybersecurity incident, or unanticipated failure of system

		disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.++	~~Elements~~elements.++ (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)
42	Reserve Sharing Group	a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (*e.g.* ten minutes). If the transaction is ramped in quicker, (*e.g.*, between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**	a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (*e.g.*, ten minutes). If the transaction is ramped in quicker~~,~~ (*e.g.*, between zero and ten minutes)~~,~~ then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**
44	Sink Balancing Authority	the Balancing Authority in which the Load (sink) is located for an Interchange Transaction.**	the Balancing Authority in which the ~~Load~~ load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.**
45	Source Balancing Authority	the Balancing Authority in which the generation (source) is located for an Interchange Transaction.**	the Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.**

48	System Operating Limit	the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.**	the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • facility ratings (applicable pre- and post-contingency equipment ratings or facility ratings) • transient stability ratings (applicable pre- and post-contingency stability limits) • voltage stability ratings (applicable pre- and post-contingency voltage stability) • system voltage limits (applicable pre- and post-contingency voltage limits).**

Implementation Plan

Project 2015-04 Alignment of Terms

Revisions to Defined Terms in the NERC Glossary of Terms Used in Reliability Standards

The drafting team proposes modifying the following Glossary of Terms definitions:	
<Term>	<Definition>
Blackstart Resource	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for ~~real~~ Real and ~~reactive~~ Reactive ~~power~~ Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Bulk Power System	Bulk~~-~~ Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (In order to remain consistent with the Federal Power Act [16 U.S.C. 824(o) and 18 C.F.R. 39.1], defined terms contained in this narrative are not capitalized.) Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.
Cascading	The uncontrolled successive loss of ~~system~~ System ~~elements~~ Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
Distribution Provider	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the ~~Distribution~~ distribution function at any voltage.

Element	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An ~~element~~ Element may be comprised of one or more components.
Generator Operator	The entity that operates generating Facility(ies) ~~unit(s)~~ and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	Entity that owns and maintains generating Facility(ies)~~units~~.
Interchange Authority	The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interconnected Operations Service	A service (exclusive of basic energy and ~~transmission~~ Transmission ~~services~~Services) that is required to support the ~~reliable~~ Reliable ~~operation~~ Operation of interconnected Bulk Electric Systems.
Interconnection	A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Load-Serving Entity	Secures energy and ~~transmission~~ Transmission ~~service~~ Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Planning Authority	The responsible entity that coordinates and integrates transmission ~~facility~~ Facilities and service plans, resource plans, and ~~protection~~ Protection ~~systems~~Systems.

Point of Receipt	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a ~~Generator~~ generator delivers its output.
Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive ~~power~~ Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive ~~power~~ Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power	The portion of electricity that supplies energy to the ~~load~~Load.
Reliability Coordinator	The entity that is the highest level of authority who is responsible for the ~~reliable~~ Reliable ~~operation~~ Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Standard	A requirement, approved by the United States Federal Energy Regulatory Commission under ~~this~~ Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk~~-~~ Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk~~-~~ Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk~~-~~ Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)

Reliable Operation	Operating the elements of the bulk-power system [Bulk- Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements. (In order to remain consistent with the Federal Power Act, defined terms contained in this narrative are not capitalized.)
Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of ~~Disturbance~~ disturbance ~~Control~~ control ~~Performance~~performance, the ~~Areas~~ areas become a Reserve Sharing Group.
Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority ~~Area~~area.
System Operating Limit	The value (such as MW, MVar, ~~A~~amperes, ~~Frequency~~ frequency or ~~Volts~~volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (~~Applicable~~ applicable pre- and post-Contingency ~~equipment~~ Equipment Ratings or ~~facility~~ Facility ~~ratings~~Ratings) • ~~Transient~~ transient ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Stability~~ stability ~~Limits~~limits) • ~~Voltage~~ voltage ~~Stability~~ stability ~~Ratings~~ ratings (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Stability~~stability) • ~~System~~ system ~~Voltage~~ voltage ~~Limits~~ limits (~~Applicable~~ applicable pre- and post-Contingency ~~Voltage~~ voltage ~~Limits~~limits)

Transmission Customer	1. Any eligible customer (or its designated agent) that can or does execute a ~~transmission~~ Transmission ~~service~~ Service agreement or can or does receive ~~transmission~~ Transmission ~~service~~Service. 2. Any of the following ~~responsible~~ entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission ~~facilities~~Facilities.
Transmission Owner	The entity that owns and maintains transmission ~~facilities~~Facilities.
Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority ~~Area~~area.
Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~transmission~~ Transmission ~~service~~ Service agreements.

Requested Retirements

- None

Prerequisite Approvals

It is requested that all proposed changes to the definitions in the NERC Rules of Procedure are approved contemporaneously with the proposed revisions to the Glossary of Terms. Additionally, it is requested that the proposed revisions do not take effect until the first day of the first calendar quarter beyond the date that the definitions are approved by applicable regulatory authorities, but no earlier than 07/01/2016.

Background

The purpose of Project 2015-04 – Alignment of Terms is to align the defined terms found in the NERC Glossary of Terms found in Reliability Standards and the Rules of Procedure. This project is necessary because currently there are defined terms that appear in both the Glossary and ROP that are inconsistent in substance and form. This causes industry confusion and may lead to inconsistent interpretation or application of the meaning of a term. Consistent definitions will enhance reliability because owners, users and operators of the BES, along with the ERO Enterprise, will have a clear and consistent understanding of the terminology used in the NERC Reliability Standards and ROP. Of the fifty-five (55) cross-over terms, forty (40) contain inconsistencies or differences in the definition narratives. To achieve consistency and alignment of these cross-over terms, the SDT is proposing revisions to twenty-six (26) Glossary terms and sixteen (16) ROP terms.

Effective Date

The definitions shall be added to the NERC Glossary of Terms used in Reliability Standards effective on the first day of the first calendar quarter beyond the date that the definitions are approved by applicable regulatory authorities, but no earlier than 07/01/2016, or in those jurisdictions where regulatory approval is not required, the definitions become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, but no earlier than 07/01/2016, or as otherwise made effective pursuant to the laws applicable to such governmental authorities.

Alignment of PRC-005 Compliance Dates

I. PRC-005 Compliance Issue and Proposal to Align Compliance Dates

Since the approval of PRC-005-2, which is currently mandatory and enforceable, a number of standards development projects have resulted in either including or excluding devices from the scope of PRC-005. Currently, there are eight approved or currently proposed PRC-005 versions, and each Version comes with a separate implementation schedule. Depending on the type of device and specific requirement in some of the PRC-005 versions, the implementation is divided into phases, requiring registered entities to gradually ensure compliance of a percentage of their devices until they reach 100% compliance.

Versions -3, -4, and -6 will require three consecutive updates to the registered entities' Protection System Maintenance Programs (PSMP), which is expected to be a time-consuming task for many. Based on the implementation plans for these three Versions, the required PSMP updates would have to be completed within a year to 18 months. According to the PRC-005 drafting team, which represents various industry members, this short period of time for review and identification of all assets subject to the revised PRC-005 Versions could lead to errors and misidentification of devices. Further, the existence of eight implementation plans could lead to misinterpretations and inconsistencies in the compliance and auditing practices throughout the ERO Enterprise.

To address this compliance issue, the PRC-005 drafting team requested that NERC align the effective dates of all outstanding PRC-005 Versions, thus simplifying the implementation schedule for this Reliability Standard. In response to the drafting team's request, NERC plans to petition the Federal Energy Regulatory Commission (FERC) to delay the implementation of PRC-005-3 and have PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4, PRC-005-5, and PRC-005-6 all become effective on the same date. NERC is also proposing that the implementation of PRC-005-2(i) is aligned with the currently effective PRC-005-2. The phased implementation approach will remain but the effective dates for each phase will align across all applicable Versions.

This proposal is reflected in the implementation plan for PRC-005-6. If supported by industry members, the implementation plan will be included in the PRC-005-6 petition to be filed with FERC for review.

II. PRC-005 Versions Overview

The draft PRC-005-6 incorporates all revisions made to PRC-005-2 as a result of the development of PRC-005-2(i), PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4, and PRC-005-5, and PRC-005-6. Version 3 added Automatic Reclosing devices; Versions 2(i), 3(i), and -5 exclude individual dispersed generation resources from the applicability of the Standard; Versions 2(ii) and 3(ii) replace the term "Special Protection System" with the term "Remedial Action Scheme"; Version 4 added Sudden Pressure Relays; and Version 6 will add supervisory relays and exclude individual dispersed generation resources from the applicability of this Reliability Standard.

From this list of all PRC-005 Versions, Version 3 is approved by FERC; PRC-005-2(i), PRC-005-2(ii), PRC-005-3(i), PRC-005-3(ii), and PRC-005-4 are pending regulatory approval; PRC-005-5 has not yet been filed for approval with FERC; and PRC-005-6 is currently under development.

III. Impact on the Reliability of the Bulk Power System and on Compliance with PRC-005

Based on the implementation schedule for the FERC-approved PRC-005-3 and estimated approval and effective dates for the remaining Versions, the delay in the implementation of PRC-005-3 created by this proposal is anticipated to be approximately one year.

The proposed changes described here and in the proposed PRC-005-6 implementation plan will not affect the immediate implementation of Versions 2(i), 3(i), and -5. These Versions exclude certain dispersed generation resources from the definition of Bulk Electric System, and from the applicability of PRC-005. Thus, registered entities that own and operate dispersed generation resources will remain unaffected by the proposed changes.

PRC-005-2(ii) and PRC-005-3(ii) reflect enhancements to the NERC Glossary of Terms related to Special Protection Systems and Remedial Action Schemes. While alignment between the standards and the Glossary of Terms is important, potential delays in this alignment would not present a risk to the reliability of the BPS. The petition requesting changes to PRC-005-2(ii) and PRC-005-3(ii) is pending and its review will likely be delayed until the Commission reviews the petition for PRC-010-1 related to Under-Voltage Load Shedding Program. Finally, the anticipated changes related to Remedial Action Schemes are minor in nature and are unlikely to introduce an actual reliability risk.

Because the Automatic Reclosing devices and Sudden Pressure Relays brought in by Versions -3 and -4 are limited in scope, a potential delay in the implementation of these Versions of PRC-005 is also unlikely to increase risk to the BPS. Many of these devices are already monitored by industry in anticipation of the upcoming compliance requirements, but may not be specifically included in the registered entities' PSMPs at this time.

IV. Benefits to Registered Entities

The proposal aims to simplify the compliance efforts of all registered entities subject to PRC-005 and give industry additional time to comply with Versions -3, -4, and -6, which require PSMP updates. Having PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4, and PRC-005-5, PRC-005-6 become effective at the same time minimizes the possibility of misinterpretations of each Version and associated compliance obligations, thus limiting the compliance risk for registered entities. In addition, the proposed changes will not affect the anticipated exclusion of certain dispersed generation resources from the applicability of the standard.

To further facilitate compliance, NERC plans to use the additional time until PRC-005-6 becomes effective to conduct outreach and provide training to ensure that registered entities are well aware and prepared to meet their obligations under the various PRC-005 Versions.

Effective Date Information

Table 1 provides information regarding each version of the PRC-005 standard.

Table 1: PRC-005 Effective Date Information		
Standard	**Effective Date[1]**	**Comments**
PRC-005-2	April 1, 2015	
PRC-005-2(i)	May 29, 2015	Proposed effective with version 2, which will be immediately following FERC Approval.
PRC-005-2(ii)	Filed and Pending Regulatory Approval	Proposed to be deferred until version 6 effective date.[2]
PRC-005-3	April 1, 2016	Proposed to be deferred until version 6 effective date.
PRC-005-3(i)	April 1, 2016	Proposed to be deferred until version 6 effective date.
PRC-005-3(ii)	Filed and Pending Regulatory Approval	Proposed to be deferred until version 6 effective date.
PRC-005-4	Filed and Pending Regulatory Approval	Proposed to be deferred until version 6 effective date.
PRC-005-5	Pending Regulatory Filing	Proposed to be deferred until version 6 effective date.
PRC-005-6	Pending Regulatory Filing	TBD

[1] The effective date listed is the start date of when the standard becomes effective. This does not include the phased in approach.

[2] This is based on when FERC approves PRC-005-6, which could be from three (3) months to one (1) year.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17.4 PRC-005-6
Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-6~~2~~ - Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

PRC-005~~-X~~-6 Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance is a revision of PRC-005-3 Protection System and Automatic Reclosing Maintenance with the stated purpose: To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

PRC-005~~-X~~-6 has five (5) requirements that address the inclusion of Sudden Pressure Relaying. A Table of minimum maintenance activities and maximum maintenance intervals for Sudden Pressure Relaying has been added to PRC-005-3 to address FERC's directives from Order 758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore Sudden Pressure Relaying Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005~~-X~~-6 map one-to-one with the requirements of PRC-005-3. The drafting team did not revise the VRFs for the requirements of PRC-005-3.

PRC-005~~-X~~-6 Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-~~6~~4 Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-~~X~~-6 Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on VSLs

In its June 19, 2008 Order on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.
- Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-~~X~~-6, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-~~X~~-6 Requirement R1.

VRF and VSL Justifications – PRC-005~~-X~~-6, R1	
Proposed VRF	**Medium**
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005~~-X~~-6, R1			
Lower	**Moderate**	**High**	**Severe**
The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).

Proposed VSL – PRC-005-~~X~~-6, R1			
Lower	**Moderate**	**High**	**Severe**
		The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-~~2~~3, and Table 5where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1)

VRF and VSL Justifications – PRC-005~~-X~~-6, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005~~-X~~-6, R1	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-~~X~~-6, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-~~X~~-6 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for.

VRF and VSL Justifications – PRC-005-X-6, R2	
Proposed VRF	**Medium**
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-X-6, R2			
Lower	**Moderate**	**High**	**Severe**
The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	N/A	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP

Proposed VSL – PRC-005~~-X~~-6, R2			
Lower	**Moderate**	**High**	**Severe**
			OR 2) Failed to reduce countable events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.

VRF and VSL Justifications – PRC-005-X-6, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-X-6, R2	
Guideline 2b: VSL Assignments that Contain Ambiguous Language	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-~~X~~-6, R3	
Proposed VRF	**High**
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-X-6, R3			
Lower	**Moderate**	**High**	**Severe**
For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-32, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-32, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-32, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-32, and Table 5.

VRF and VSL Justificati3ons – PRC-005-X-6, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-X-6, R3	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-~~X~~-6, R4	
Proposed VRF	**High**
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-X-6, R4			
Lower	**Moderate**	**High**	**Severe**
For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.

VRF and VSL Justifications – PRC-005-X-6, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-X-6, R4	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-~~X~~-6, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-X-6, R5			
Proposed VRF	**Medium**		
	However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-X-6, R5			
Lower	**Moderate**	**High**	**Severe**
The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

VRF and VSL Justifications – PRC-005-6~~X~~, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirement in PRC-005~~-X~~-6 is identical to that in PRC-005-3, which has identical VSLs.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-X-6, R5	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications — PRC-005-4, R6	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17.4 PRC-005-6
Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-6 - Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

PRC-005-6 Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance is a revision of PRC-005-3 Protection System and Automatic Reclosing Maintenance with the stated purpose: To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

PRC-005-6 has five (5) requirements that address the inclusion of Sudden Pressure Relaying. A Table of minimum maintenance activities and maximum maintenance intervals for Sudden Pressure Relaying has been added to PRC-005-3 to address FERC's directives from Order 758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore Sudden Pressure Relaying Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005-6 map one-to-one with the requirements of PRC-005-3. The drafting team did not revise the VRFs for the requirements of PRC-005-3.

PRC-005-6 Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-6 Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-6 Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on VSLs

In its June 19, 2008 Order on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.
- Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-6, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-6 Requirement R1.

VRF and VSL Justifications – PRC-005-6, R1			
Proposed VRF	**Medium**		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-6, R1			
Lower	**Moderate**	**High**	**Severe**
The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).

Proposed VSL – PRC-005-6, R1			
Lower	**Moderate**	**High**	**Severe**
		The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1)

VRF and VSL Justifications – PRC-005-6, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-6, R1	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-6, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-6 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for.

VRF and VSL Justifications – PRC-005-6, R2			
Proposed VRF	**Medium**		
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-6, R2			
Lower	**Moderate**	**High**	**Severe**
The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	N/A	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP

Proposed VSL – PRC-005-6, R2			
Lower	**Moderate**	**High**	**Severe**
			OR 2) Failed to reduce countable events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.

VRF and VSL Justifications – PRC-005-6, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-6, R2	
Guideline 2b: VSL Assignments that Contain Ambiguous Language	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-6, R3	
Proposed VRF	**High**
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-6, R3			
Lower	**Moderate**	**High**	**Severe**
For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5.

VRF and VSL Justificati3ons – PRC-005-6, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-6, R3	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-6, R4	
Proposed VRF	**High**
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-6, R4			
Lower	**Moderate**	**High**	**Severe**
For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.

VRF and VSL Justifications – PRC-005-6, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-6, R4	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-6, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-6, R5			
Proposed VRF	**Medium**		
	However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-6, R5			
Lower	**Moderate**	**High**	**Severe**
The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

VRF and VSL Justifications – PRC-005-6, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirement in PRC-005-6 is identical to that in PRC-005-3, which has identical VSLs.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-6, R5	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Supplementary Reference and FAQ

PRC-005-4 Protection System Maintenance and Testing

April 2015~~October 2014~~

RELIABILITY | ACCOUNTABILITY

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1. Introduction and Summary

Note: This supplementary reference for PRC-005-4 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-4 addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-4.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-4 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

"*...affecting the reliability of the Bulk Electric System (BES)…*"

To the present language:

"*…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).*"

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be

Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.
This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Remedial Action Schemes is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5 and 4.2.6.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.~~6~~7.

Sudden Pressure Relaying is addressed in PRC-005-4 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5.2~~,~~, 4.2.5.3, and 4.2.6. ~~and 4.2.5.4.~~

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.~~7~~6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.~~7~~6 Automatic Reclosing

4.2.~~7~~6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.

4.2.~~7~~6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.~~7~~6.1

when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.7~~6~~.3 Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.7~~6~~ establishes that Automatic Reclosing addressed in 4.2.7~~6~~.1 and 4.2.7~~6~~.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

Additionally, Footnote 2 to Applicability Section 4.2.7~~6~~.1 advises that the entity's PSMP needs to remain current regarding the applicability of Automatic Reclosing Components relative to the largest generating unit within the Balancing Authority Area or Reserve Sharing Group.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Remedial Action Schemes, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

Why did the standard drafting team not include IEEE device numbers to describe Automatic Reclosing Relays?

The drafting team elected not to include IEEE device numbers to describe Automatic Reclosing because Automatic Reclosing component type could be a stand-alone electromechanical relay; or could be the 79 function within a microprocessor based multi-function relay(11).

What is synchronizing or synchronism ~~(Sync-Check - (25)) – check relay (Sync-Check - 25)~~?

A synchronizing device that produces an output that supervises ~~causes~~ closure of a circuit breaker between two circuits whose voltages are within prescribed limits of magnitude and~~, phase angle, and frequency~~. It may or may not include voltage or speed control. A sync-check relay permits the paralleling of two circuits that are within prescribed (usually wider) limits of voltage magnitude and~~, phase angle, and frequency~~.

~~*Is a sync-check (25) relay included in the Automatic Reclosing Control Circuitry?*~~

~~Where sync-check relays are included in an Automatic Reclosing scheme that is part of an RAS, the sync-check would be included in the control circuitry (Table 4-2(ab)).~~

~~Where sync-check relays are included in an Automatic Reclosing scheme that is not part of an RAS, the sync-check would not be included in the control circuitry (Table 4-2(a)).~~

~~The SDT asserts that a sync check (25) relay does not initiate closing but rather enables or disables closing and is not considered a part of the actual Automatic Reclosing control circuitry when not part of an RAS.~~

How do I interpret Applicability Section 4.2.7~~6~~ to determine applicability in the following examples:

At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

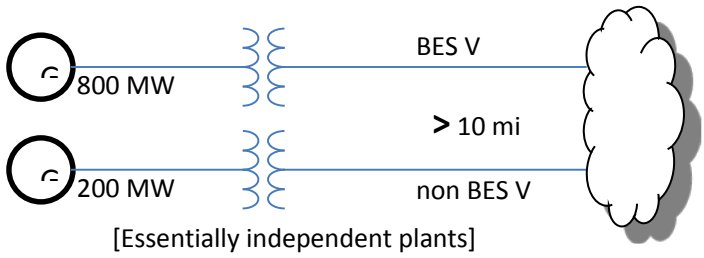
Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW

is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



[Essentially independent plants]

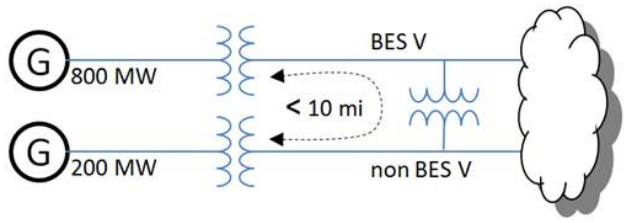
Gross Capacity	**Automatic Reclosing in scope**
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



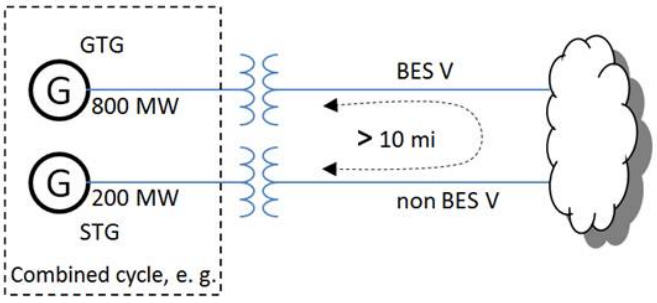
Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



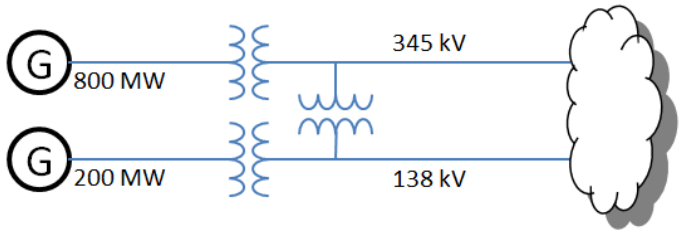
Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.7~~6~~.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.7~~6~~.1.



Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.7~~6~~.2 specify "10 circuit miles"?

As noted in "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.7~~6~~.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be "one bus away" from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. "One bus away" is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not 'installed for the purpose of detecting' these faults.

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-4?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure

Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices ("Buchholz") monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-4?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Are pressure relief devices included in the scope of PRC-005-4?

No. PRDs are not included in the Sudden Pressure Relaying definition.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-4?

No, Applicability 4.2.1, ~~4.2.5.2, 4.2.5.3~~4.2.5, and 4.2.6~~, 4.2.5.4~~, explicitly describes what Sudden Pressure Relaying is included within the standard.

Are non-electrical sensing devices (other than fault pressure relays) such as low oil level or high winding temperatures included in PRC-005-4?

No, based on the SPCS technical document, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013," the only applicable non-electrical sensing devices are Sudden Pressure Relays.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: "A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely."

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self-monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self-monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a "lock-out." Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the "soft 86" would still need applicable verification activities performed, but the actual "86" does not have to be "electrically operated" or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — ~~Detect visible~~Examine for signs of Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Supervisory relay(s) – relay(s) that perform voltage and/or sync check functions that enables or disables operation of the reclosing relay
- Voltage sensing devices associated with the supervisory relay(s)
- Control circuitry associated with the reclosing relay or supervisory relay(s)~~.~~

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the ~~two~~ four specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-32, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-4 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-4 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-4 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades

might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "...demonstrate efforts to correct an Unresolved Maintenance Issue..."; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory

discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

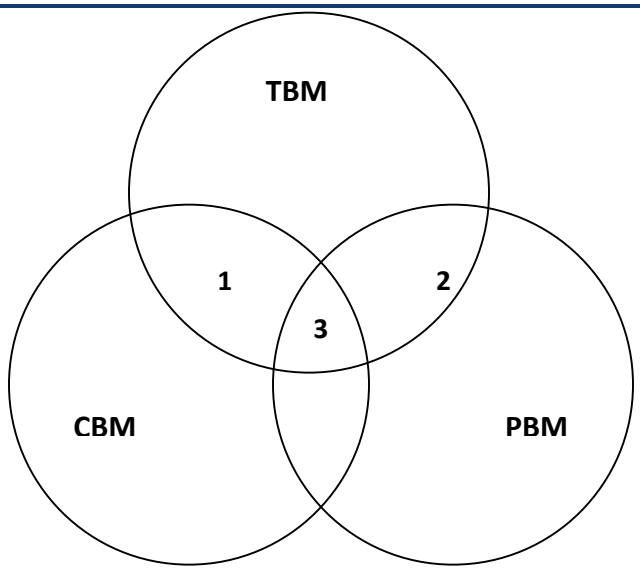
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



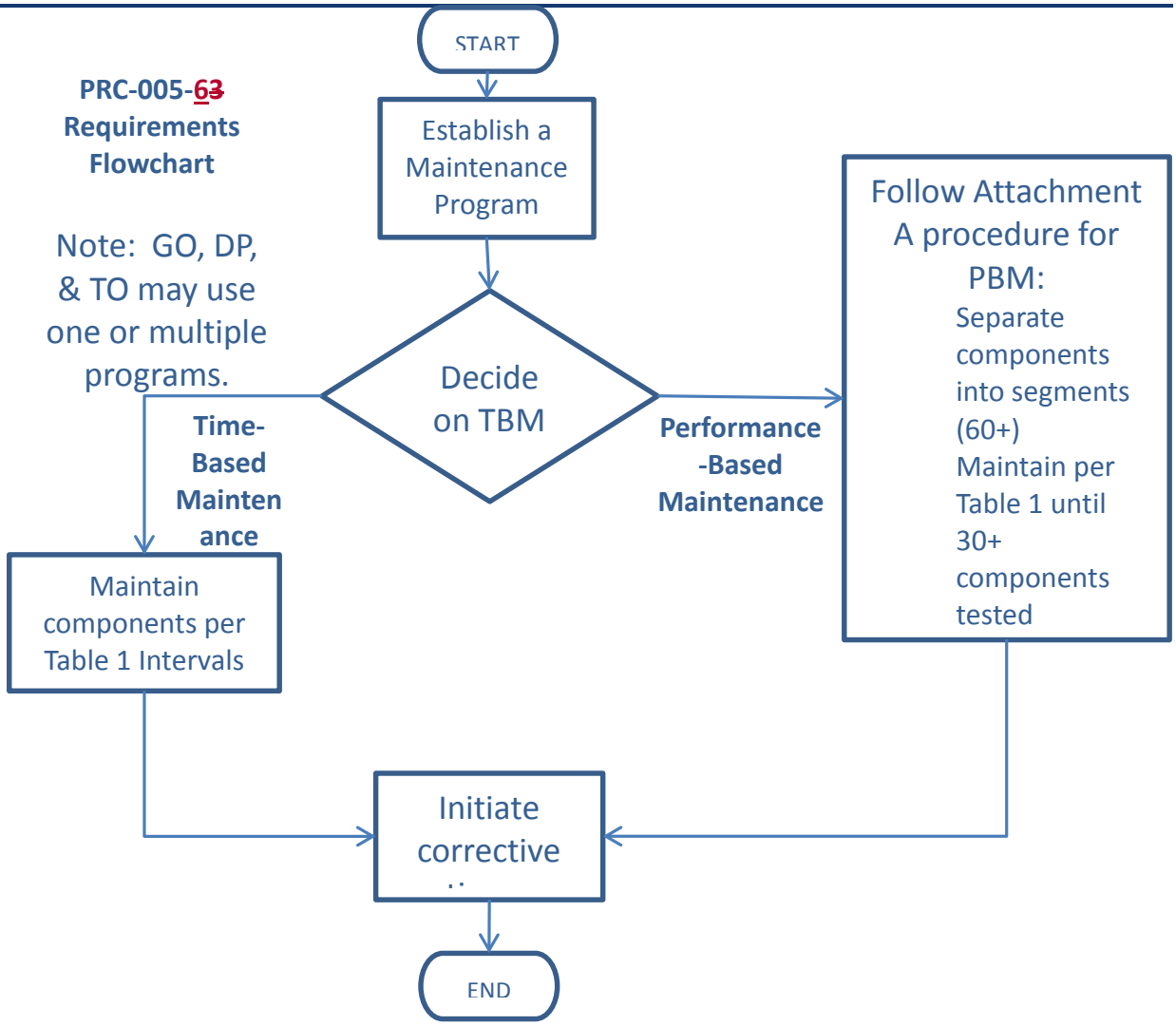
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a "flow chart" of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or

CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct ~~any~~ identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.2) of the standard, is it necessary to provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

The applicability of R1.2 depends on the BES definition for Protection System to identify what components are to be covered by the Standard. One type of component is described as "Protective relays which respond to electrical quantities". Would a protection function that is embedded in a Generator's voltage regulator meet the BES defintion for Protection System and thus be included in R1.2?

Yes. The fact that these functions are implemented by an excitation system or voltage regulator rather than a classical looking relay is immaterial. The devices monitor electrical parameters such as voltage and/or current and cause a trip of the generator in response to these signals. By implementing these functions in the excitation system, the excitation system has in essence become an elaborate form of a microprocessor relay.

The voltage regulator processes electrical quantities and has an output that trips the generator breaker, quite often through a lockout. Examples include voltage regulator electronic cards that monitor voltage for high V/Hz, high exciter field voltage or both. In older generation regulators (1980s and 1990s) the protection functions are essentially electronic relays (not

electromechanical or microprocessor based but using transistors and potentiometers). Should either excess voltage condition be true, a contact mounted on the voltage regulator electronics board closes which, in turn, goes to an auxiliary relay or activates a lockout relay directly. The electronic quantities monitored include exciter field voltage, generator current, and generator terminal voltage.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-4. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-4.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May) would still

be due four months later therefore the activity is due again July. Basically every "four Calendar Months" means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance

- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarms. (monitored)

- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)
- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Remedial Action Schemes. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, Table 4-1 through Table 4-3~~2~~, and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems, Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and RAS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and RAS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-4:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
    - Table 1-1 is for protective relays,
    - Table 1-2 is for the associated communications systems,
    - Table 1-3 is for current and voltage sensing devices,
    - Table 1-4 is for station dc supply and
    - Table 1-5 is for control circuits.
    - Table 2, is for alarms; this was broken out to simplify the other tables.
    - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
    - Table 4 is for Automatic Reclosing.
    - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-

hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-4. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-4, most notable of which is an entity using performance based maintenance methodology.

If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

If an entity has a Time-Based Maintenance program and the PSMP is more stringent than PRC-005-4, they will only be audited in accordance with the standard (minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3~~2~~, and Table 5).

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc., are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or RAS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this

standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-4 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-4 is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).

7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.

8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.

9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously

disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Remedial Action Schemes?

No. All portions of the -RAS need to be maintained, and the portions must overlap, but the overall RAS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about RAS interfaces between different entities or owners?

As in all of the Protection System requirements, RAS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Remedial Action Schemes?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Remedial Action Schemes (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Remedial Action Schemes or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the RAS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for RAS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an RAS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an RAS scheme should that occur. Forced trip tests of circuit breakers (etc.) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays

- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output

terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an RAS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-4 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	**Data Retention Period**
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit
6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the

maintenance activities specified in the Tables of PRC-005-4, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-4 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-4 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-4 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the "Calendar Year" language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To

provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self-test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years –

the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for "time-interval extensions" or "grace periods" to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. "Maximum time intervals" by their very term negates any "time-interval extension" or "grace periods." To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was "…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…" The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity's use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Table 4-1 through Table 4-3~~2~~, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance

intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure

rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, "reset the clock" on everything you've done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that "resetting the clock" should not be construed as interfering with an entity's routine testing schedule because the "clock-reset" would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually

could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that "replaced relay" will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of

monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the

operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent

(standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle.

(However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-4 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-4. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-4 to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in PRC-005-4 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-4 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-4 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Tables 1, 3, 4 and 5 and any associated sub-tables~~Table 3~~.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Tables 1, 3, 4 and 5 and any associated sub-tables~~Table 3~~.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-4 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
    - There is no specific protective relay commissioning test or relay routine test mandated.
    - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and VArs around the entire bus; this should add up to zero watts and zero VArs, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "… verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being

shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately "verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-4 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-4 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-4 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-4 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply

- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,

- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, "station batteries" are replaced with "station dc supply" to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-4 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.
At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.
- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time,

a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than

every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for

the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external

circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance "as designed" vs. battery performance "as manufactured." The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer's rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trend line against the established baseline. The type of probe and its location (post, connector, etc.) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be "forming" after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should

demonstrate that an “adequate” ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-4 is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.
Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the “Unintentional dc Grounds” requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional ~~DC~~ dc ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional ~~DC~~ dc grounds. The standard merely requires that a check be made for the existence of u~~U~~nintentional dc~~DC~~ g~~G~~rounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for u~~U~~nintentional ~~DC~~ dc g~~G~~rounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-4 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac

current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending

of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid-1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to

measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do

the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self-checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to "verify station dc supply voltage" every "4 calendar months" (see table 1-4(a)), the owner can install a monitoring and alarming device "with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure" and "no periodic verification of station dc supply voltage is required" (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install "electrolyte level monitoring and alarming in every cell" and "unintentional dc ground monitoring and alarming" (see second and third rows of table 1-4(f)), the owner will have to "inspect electrolyte level and for unintentional grounds" every "4 calendar months" (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then

interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to "Protection System Control Circuitry", rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the "channel" as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and

set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

When do I need to have the initial maintenance of Automatic Reclosing Components completed upon change of the largest BES generating unit in the BA/RSG?

The maintenance interval, for newly identified Automatic Reclosing Components, starts when a change in the largest BES generating unit is determined by the BA/RSG. The first maintenance records for newly identified Automatic Reclosing Components should be dated no later than the maximum maintenance interval after the identification date. The maximum maintenance intervals for each newly identified Component are defined in Table 4. No activities or records are required prior to the date of identification.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature auto reclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that <u>is not</u> part of an RAS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that <u>is</u> part of an RAS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the RAS, and must be verified.

Why is maintenance of supervisory relays now included in PRC-005 for Automatic Reclosing?

Proper performance of supervising relays supports the reliability of the BES because some conditions can result in a premature closing command. -An example of this would be an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, sync window verification)

My reclosing circuitry contains the following inputs listed below; what supervising relays would need to tested per PRC-005?:

- 79/ON – Supervisory contact which turns Automatic reclosing ON or OFF
- 52 – Supervisory contact which provides breaker indication ("b" contact)
- 86 - Supervisory contact from a lockout relay
- 79 – Supervisory contact from a reclosing relay
- 25 – Supervisory contact from a sync-check relay
- 27 or 59 – Supervisory contact from a undervoltage of overvoltage relay

Supervising Relays are defined in this standard as "relay(s) that perform voltage and/or sync check functions that enables or disables operation of the reclosing relay." The 79/ON, 52, and 86 would not need to be included. However, the 79, 25, and 27 or 59 would be included because they are supervisory devices that are either associated with autoreclosing, sync-checks, and/or voltage.

The sync check and voltage check functions are part of my microprocessor reclosing relay. Are there any test requirements for these internal supervisory functions?

A microprocessor reclosing relay that is using internal sync check or voltage check supervisory functions is a combinational reclosing and supervisory relay (i.e. 79/25)-. The maintenance activities for both a reclosing relay and supervisory relay would apply. The voltage sensing devices providing input to a combinational reclosing and supervisory relay would require the activities in Table 4-3.

Is it necessary to verify the close signal operates the breaker?

Only when the control circuitry associated with automatic reclosing is a part of a RAS, then all paths that are essential for proper operation of the RAS must be verified, per table 4-2(b).

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-4, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013", for a discussion of Sudden Pressure Relaying as addressed in PRC-005-4.

15.9.1 Frequently Asked Questions:

How do I verify the pressure or flow sensing mechanism is operable?

Maintenance activities for the fault pressure relay associated with Sudden Pressure Relaying in PRC-005-4 are intended to verify that the pressure and/or flow sensing mechanism are functioning correctly. Beyond this, PRC-005-4 requires no calibration (adjusting the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement) or testing (applying signals to a component to observe functional performance or output behavior, or to diagnose problems) activities. For example, some designs of flow sensing mechanisms allow the operation of a test switch to actuate the limit switch of the flow sensing mechanism. Operation of this test switch and verification of the flow sensing mechanism would meet the requirements of the maintenance activity. Another example involves a gas pressure sensing mechanism which is isolated by a test plug. Removal of the plug and verification of the bellows mechanism would meet the requirements of the maintenance activity.

Why the 6-year maximum maintenance interval for fault pressure relays?

The SDT established the six-year maintenance interval for fault pressure relays (see Table 5, PRC-005-4) based on the recommendation of the System Protection and Control Subcommittee (SPCS). The technical experts of the SPCS were tasked with developing the technical documents to:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

Excerpt from the SPCS technical report: "In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the "sudden pressure relay" (SPR) originally manufactured by Westinghouse, the "rapid pressure rise relay" (RPR) manufactured by Qualitrol, and a variety of Buchholz relays.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results

	Transmission Owner	Generator Owner
Number of responding owners that trip with Sudden Pressure Relays:	67	84
Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%

Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

The SPCS discussed the potential difference between the recommended intervals for fault pressure relaying and intervals for transformer maintenance. The SPCS developed the recommended intervals for fault pressure relaying by comparing fault pressure relaying to Protection System Components with similar physical attributes. The SPCS recognized that these intervals may be shorter than some existing or future transformer maintenance intervals, but believed it to be more important to base intervals for fault pressure relaying on similar Protection System Components than transformer maintenance intervals.

The maintenance interval for fault pressure relays can be extended by utilizing performance-based maintenance thereby allowing entities that have maintenance intervals for transformers in excess of six years, to align them.

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables. Do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we use Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records

- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-4?

Maintaining evidence for operation of Remedial Action Schemes could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-4.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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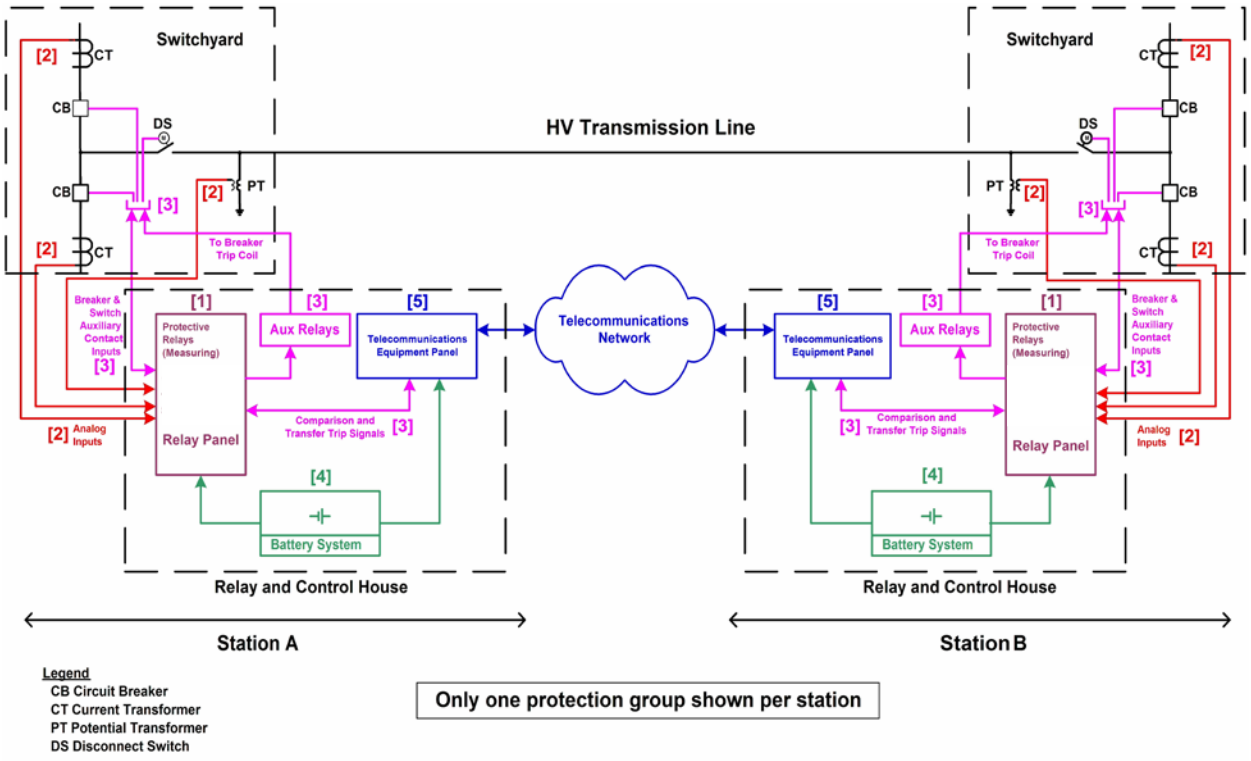
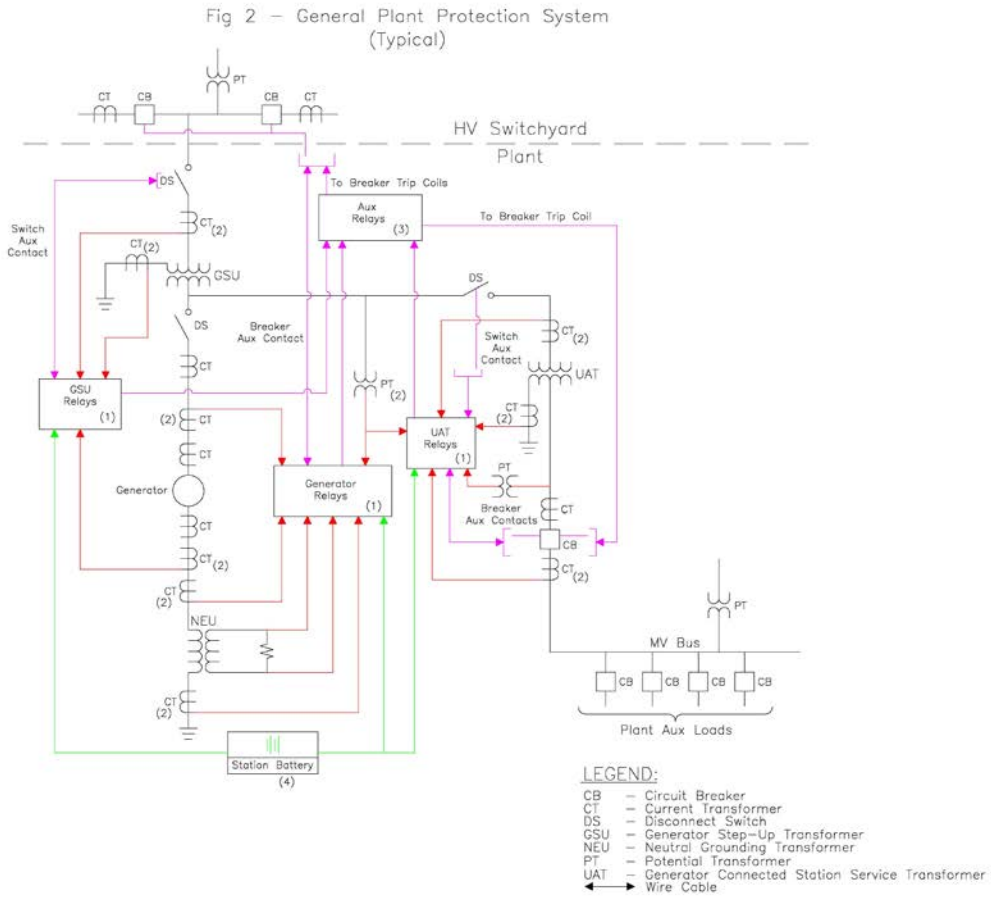
Figures

Figure 1: Typical Transmission System



For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

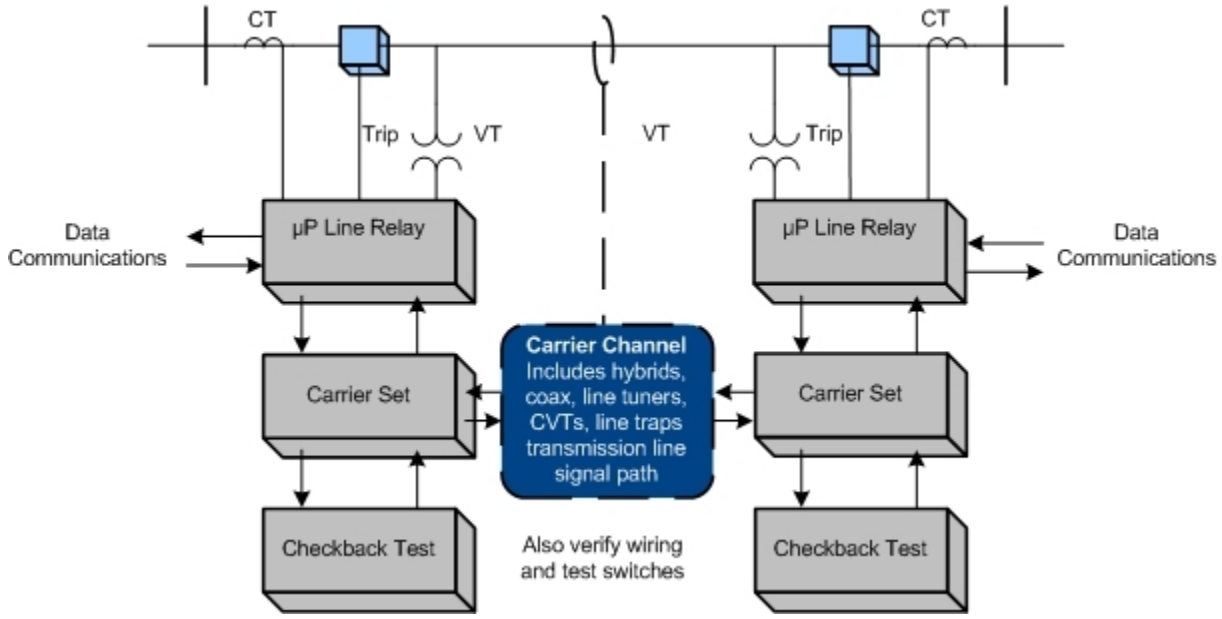
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including ~~sync-check systems~~, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

Additional information can be found in References

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

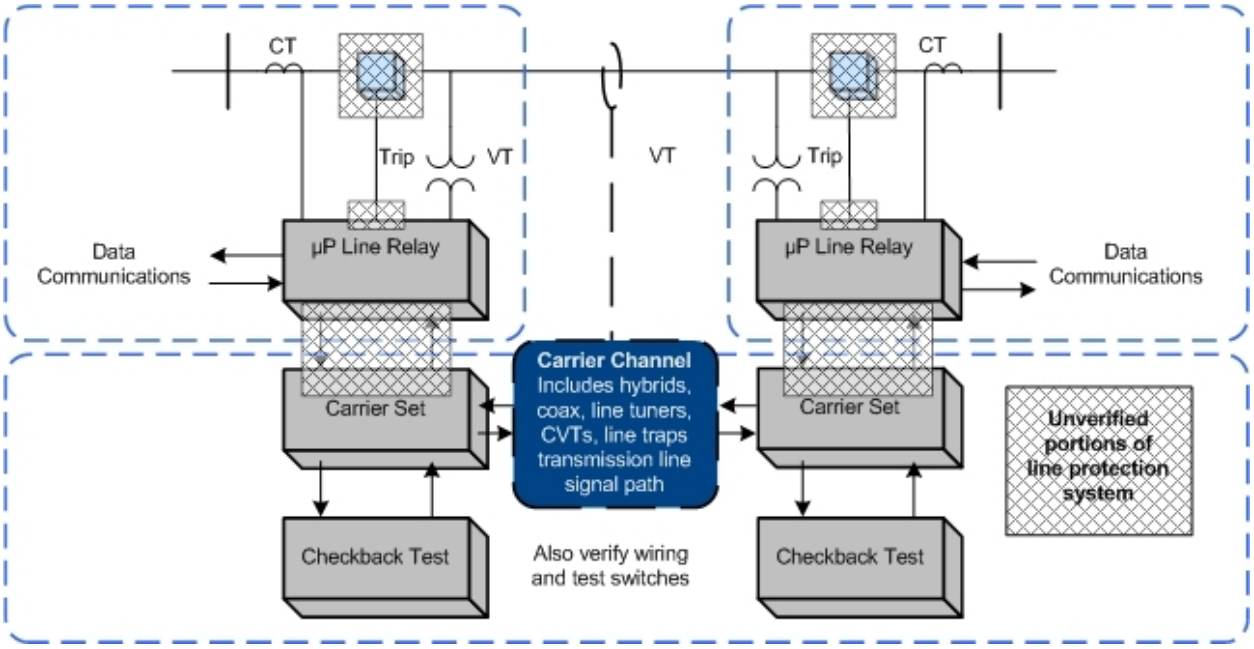
1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One

effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-4 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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Supplementary Reference and FAQ

PRC-005-4 Protection System Maintenance and Testing

April 2015

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1. Introduction and Summary

Note: This supplementary reference for PRC-005-4 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-4 addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-4.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-4 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:

"*...affecting the reliability of the Bulk Electric System (BES)…*"

To the present language:

"*…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).*"

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be

Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.
This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Remedial Action Schemes is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5 and 4.2.6.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 94 (tripping or trip-free relay), as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage-sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.7.

Sudden Pressure Relaying is addressed in PRC-005-4 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5.2, 4.2.5.3, and 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.7 of the Applicability specifically limits the applicable reclosing relays to:

4.2.7 Automatic Reclosing

4.2.7.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.

4.2.7.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.7.3 Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.7 establishes that Automatic Reclosing addressed in 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

Additionally, Footnote 2 to Applicability Section 4.2.7.1 advises that the entity's PSMP needs to remain current regarding the applicability of Automatic Reclosing Components relative to the largest generating unit within the Balancing Authority Area or Reserve Sharing Group.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Remedial Action Schemes, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

Why did the standard drafting team not include IEEE device numbers to describe Automatic Reclosing Relays?

The drafting team elected not to include IEEE device numbers to describe Automatic Reclosing because Automatic Reclosing component type could be a stand-alone electromechanical relay; or could be the 79 function within a microprocessor based multi-function relay(11).

What is synchronizing or synchronism check relay (Sync-Check - 25)?

A synchronizing device that produces an output that supervises closure of a circuit breaker between two circuits whose voltages are within prescribed limits of magnitude and phase angle. It may or may not include voltage or speed control. A sync-check relay permits the paralleling of two circuits that are within prescribed (usually wider) limits of voltage magnitude and phase angle.

How do I interpret Applicability Section 4.2.7 to determine applicability in the following examples:

At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

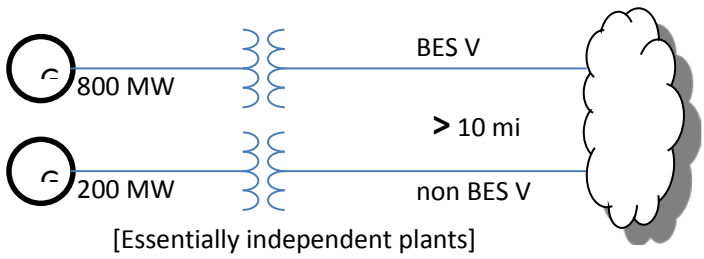
Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW

is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



[Essentially independent plants]

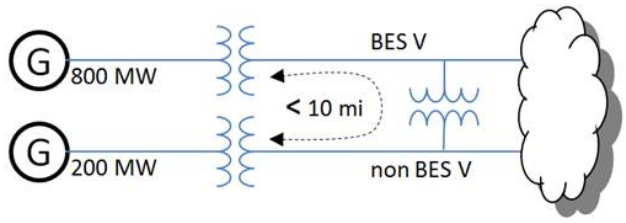
Gross Capacity	**Automatic Reclosing in scope**
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



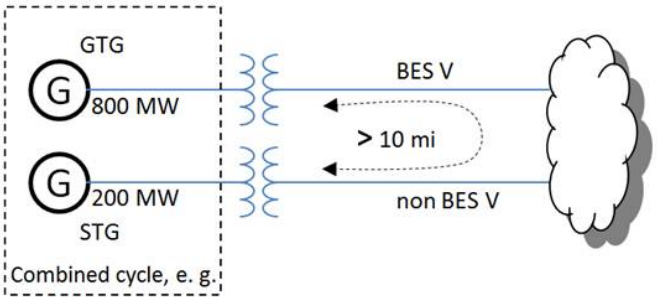
Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



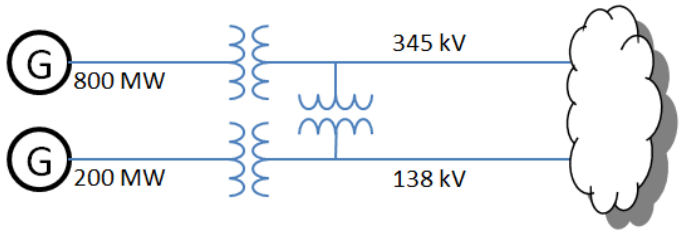
Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.7.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.7.1.



Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.7.2 specify "10 circuit miles"?

As noted in "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.7.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be "one bus away" from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. "One bus away" is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not 'installed for the purpose of detecting' these faults.

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-4?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure

Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices ("Buchholz") monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-4?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Are pressure relief devices included in the scope of PRC-005-4?

No. PRDs are not included in the Sudden Pressure Relaying definition.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-4?

No, Applicability 4.2.1, 4.2.5, and 4.2.6, explicitly describes what Sudden Pressure Relaying is included within the standard.

Are non-electrical sensing devices (other than fault pressure relays) such as low oil level or high winding temperatures included in PRC-005-4?

No, based on the SPCS technical document, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013," the only applicable non-electrical sensing devices are Sudden Pressure Relays.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self-monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self-monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a "lock-out." Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the "soft 86" would still need applicable verification activities performed, but the actual "86" does not have to be "electrically operated" or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Supervisory relay(s) – relay(s) that perform voltage and/or sync check functions that enables or disables operation of the reclosing relay
- Voltage sensing devices associated with the supervisory relay(s)
- Control circuitry associated with the reclosing relay or supervisory relay(s)

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the four specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-4 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-4 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-4 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades

might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "...demonstrate efforts to correct an Unresolved Maintenance Issue..."; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory

discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

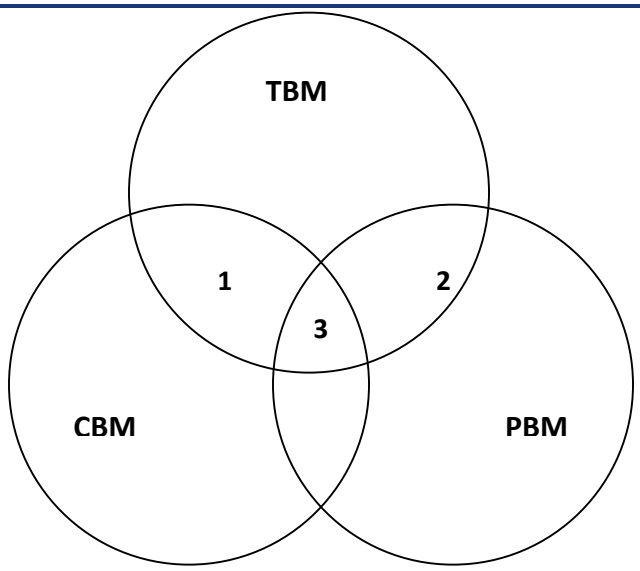
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



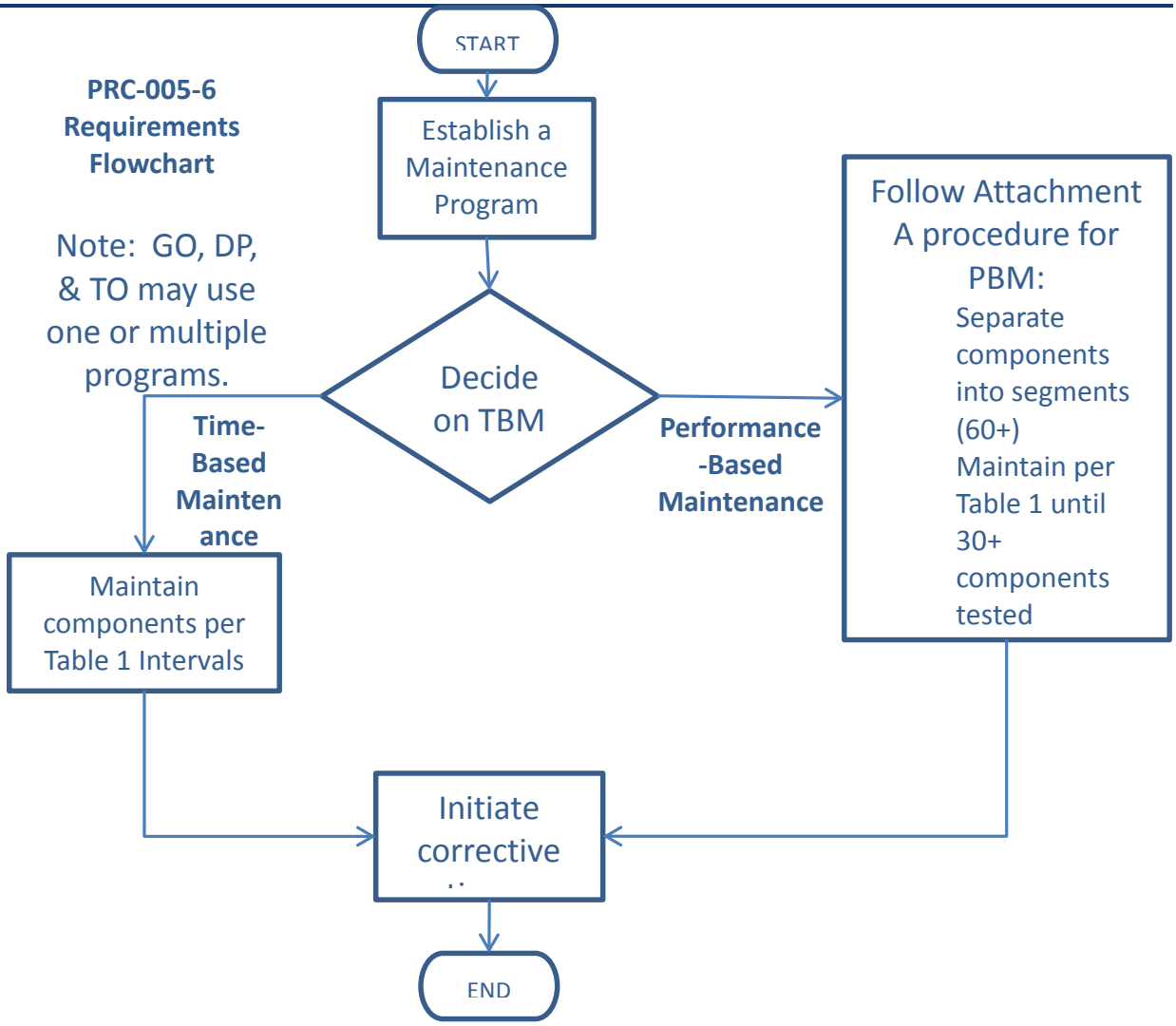
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a "flow chart" of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or

CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.2) of the standard, is it necessary to provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

The applicability of R1.2 depends on the BES definition for Protection System to identify what components are to be covered by the Standard. One type of component is described as "Protective relays which respond to electrical quantities". Would a protection function that is embedded in a Generator's voltage regulator meet the BES defintion for Protection System and thus be included in R1.2?

Yes. The fact that these functions are implemented by an excitation system or voltage regulator rather than a classical looking relay is immaterial. The devices monitor electrical parameters such as voltage and/or current and cause a trip of the generator in response to these signals. By implementing these functions in the excitation system, the excitation system has in essence become an elaborate form of a microprocessor relay.

The voltage regulator processes electrical quantities and has an output that trips the generator breaker, quite often through a lockout. Examples include voltage regulator electronic cards that monitor voltage for high V/Hz, high exciter field voltage or both. In oldergeneration regulators (1980s and 1990s) the protection functions are essentially electronic relays (not

electromechanical or microprocessor based but using transistors and potentiometers). Should either excess voltage condition be true, a contact mounted on the voltage regulator electronics board closes which, in turn, goes to an auxiliary relay or activates a lockout relay directly. The electronic quantities monitored include exciter field voltage, generator current, and generator terminal voltage.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-4. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-4.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May) would still

be due four months later therefore the activity is due again July. Basically every "four Calendar Months" means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance

- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarms. (monitored)

- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)
- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Remedial Action Schemes. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, Table 4-1 through Table 4-3, and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems, Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and RAS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and RAS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-4:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
    - Table 1-1 is for protective relays,
    - Table 1-2 is for the associated communications systems,
    - Table 1-3 is for current and voltage sensing devices,
    - Table 1-4 is for station dc supply and
    - Table 1-5 is for control circuits.
    - Table 2, is for alarms; this was broken out to simplify the other tables.
    - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
    - Table 4 is for Automatic Reclosing.
    - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-

hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-4. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-4, most notable of which is an entity using performance based maintenance methodology.

If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

If an entity has a Time-Based Maintenance program and the PSMP is more stringent than PRC-005-4, they will only be audited in accordance with the standard (minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5).

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc., are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or RAS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this

standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-4 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-4 is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).

7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.

8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.

9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously

disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Remedial Action Schemes?

No. All portions of the -RAS need to be maintained, and the portions must overlap, but the overall RAS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about RAS interfaces between different entities or owners?

As in all of the Protection System requirements, RAS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Remedial Action Schemes?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Remedial Action Schemes (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Remedial Action Schemes or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the RAS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for RAS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an RAS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an RAS scheme should that occur. Forced trip tests of circuit breakers (etc.) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays

- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output

terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an RAS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-4 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	**Data Retention Period**
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit
6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the

maintenance activities specified in the Tables of PRC-005-4, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-4 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-4 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components, such that a properly built and commission tested Protection System will continue to function as designed over its service life.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-4 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the "Calendar Year" language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To

provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self-test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years –

the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for "time-interval extensions" or "grace periods" to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. "Maximum time intervals" by their very term negates any "time-interval extension" or "grace periods." To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was "…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…" The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity's use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Table 4-1 through Table 4-3, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance

intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure

rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, "reset the clock" on everything you've done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that "resetting the clock" should not be construed as interfering with an entity's routine testing schedule because the "clock-reset" would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually

could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that "replaced relay" will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of

monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the

operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent

(standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle.

(However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-4 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-4. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-4 to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in PRC-005-4 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-4 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-4 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Tables 1, 3, 4 and 5 and any associated sub-tables.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Tables 1, 3, 4 and 5 and any associated sub-tables.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-4 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a Faulted Element of the BES. Devices that sense thermal, vibration, seismic, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
    - There is no specific protective relay commissioning test or relay routine test mandated.
    - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and VArs around the entire bus; this should add up to zero watts and zero VArs, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "… verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being

shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately "verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-4 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-4 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-4 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-4 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply

- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,

- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, "station batteries" are replaced with "station dc supply" to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-4 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.
At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.
- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time,

a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than

every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for

the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external

circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance "as designed" vs. battery performance "as manufactured." The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer's rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trend line against the established baseline. The type of probe and its location (post, connector, etc.) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be "forming" after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should

demonstrate that an “adequate” ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-4 is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.
Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the “Unintentional dc Grounds” requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional dc ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional dc grounds. The standard merely requires that a check be made for the existence of unintentional dc grounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for unintentional dc grounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-4 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac

current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending

of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid-1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to

measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do

the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self-checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to “verify station dc supply voltage” every “4 calendar months” (see table 1-4(a)), the owner can install a monitoring and alarming device “with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure” and “no periodic verification of station dc supply voltage is required” (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install “electrolyte level monitoring and alarming in every cell” and “unintentional dc ground monitoring and alarming” (see second and third rows of table 1-4(f)), the owner will have to “inspect electrolyte level and for unintentional grounds” every “4 calendar months” (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then

interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to "Protection System Control Circuitry", rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the "channel" as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and

set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

When do I need to have the initial maintenance of Automatic Reclosing Components completed upon change of the largest BES generating unit in the BA/RSG?

The maintenance interval, for newly identified Automatic Reclosing Components, starts when a change in the largest BES generating unit is determined by the BA/RSG. The first maintenance records for newly identified Automatic Reclosing Components should be dated no later than the maximum maintenance interval after the identification date. The maximum maintenance intervals for each newly identified Component are defined in Table 4. No activities or records are required prior to the date of identification.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature auto reclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that <u>is not</u> part of an RAS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that <u>is</u> part of an RAS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the RAS, and must be verified.

Why is maintenance of supervisory relays now included in PRC-005 for Automatic Reclosing?

Proper performance of supervising relays supports the reliability of the BES because some conditions can result in a premature closing command. An example of this would be an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, sync window verification)

My reclosing circuitry contains the following inputs listed below; what supervising relays would need to tested per PRC-005?

- 79/ON – Supervisory contact which turns Automatic reclosing ON or OFF
- 52 – Supervisory contact which provides breaker indication ("b" contact)
- 86 - Supervisory contact from a lockout relay
- 79 – Supervisory contact from a reclosing relay
- 25 – Supervisory contact from a sync-check relay
- 27 or 59 – Supervisory contact from a undervoltage of overvoltage relay

Supervising Relays are defined in this standard as "relay(s) that perform voltage and/or sync check functions that enables or disables operation of the reclosing relay." The 79/ON, 52, and 86 would not need to be included. However, the 79, 25, and 27 or 59 would be included because they are supervisory devices that are either associated with autoreclosing, sync-checks, and/or voltage.

The sync check and voltage check functions are part of my microprocessor reclosing relay. Are there any test requirements for these internal supervisory functions?

A microprocessor reclosing relay that is using internal sync check or voltage check supervisory functions is a combinational reclosing and supervisory relay (i.e. 79/25). The maintenance activities for both a reclosing relay and supervisory relay would apply. The voltage sensing devices providing input to a combinational reclosing and supervisory relay would require the activities in Table 4-3.

Is it necessary to verify the close signal operates the breaker?

Only when the control circuitry associated with automatic reclosing is a part of a RAS, then all paths that are essential for proper operation of the RAS must be verified, per table 4-2(b).

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-4, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013", for a discussion of Sudden Pressure Relaying as addressed in PRC-005-4.

15.9.1 Frequently Asked Questions:

How do I verify the pressure or flow sensing mechanism is operable?

Maintenance activities for the fault pressure relay associated with Sudden Pressure Relaying in PRC-005-4 are intended to verify that the pressure and/or flow sensing mechanism are functioning correctly. Beyond this, PRC-005-4 requires no calibration (adjusting the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement) or testing (applying signals to a component to observe functional performance or output behavior, or to diagnose problems) activities. For example, some designs of flow sensing mechanisms allow the operation of a test switch to actuate the limit switch of the flow sensing mechanism. Operation of this test switch and verification of the flow sensing mechanism would meet the requirements of the maintenance activity. Another example involves a gas pressure sensing mechanism which is isolated by a test plug. Removal of the plug and verification of the bellows mechanism would meet the requirements of the maintenance activity.

Why the 6-year maximum maintenance interval for fault pressure relays?

The SDT established the six-year maintenance interval for fault pressure relays (see Table 5, PRC-005-4) based on the recommendation of the System Protection and Control Subcommittee (SPCS). The technical experts of the SPCS were tasked with developing the technical documents to:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

Excerpt from the SPCS technical report: "In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the "sudden pressure relay" (SPR) originally manufactured by Westinghouse, the "rapid pressure rise relay" (RPR) manufactured by Qualitrol, and a variety of Buchholz relays.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results

	Transmission Owner	Generator Owner
Number of responding owners that trip with Sudden Pressure Relays:	67	84
Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%

Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

The SPCS discussed the potential difference between the recommended intervals for fault pressure relaying and intervals for transformer maintenance. The SPCS developed the recommended intervals for fault pressure relaying by comparing fault pressure relaying to Protection System Components with similar physical attributes. The SPCS recognized that these intervals may be shorter than some existing or future transformer maintenance intervals, but believed it to be more important to base intervals for fault pressure relaying on similar Protection System Components than transformer maintenance intervals.

The maintenance interval for fault pressure relays can be extended by utilizing performance-based maintenance thereby allowing entities that have maintenance intervals for transformers in excess of six years, to align them.

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables. Do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we use Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records

- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-4?

Maintaining evidence for operation of Remedial Action Schemes could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-4.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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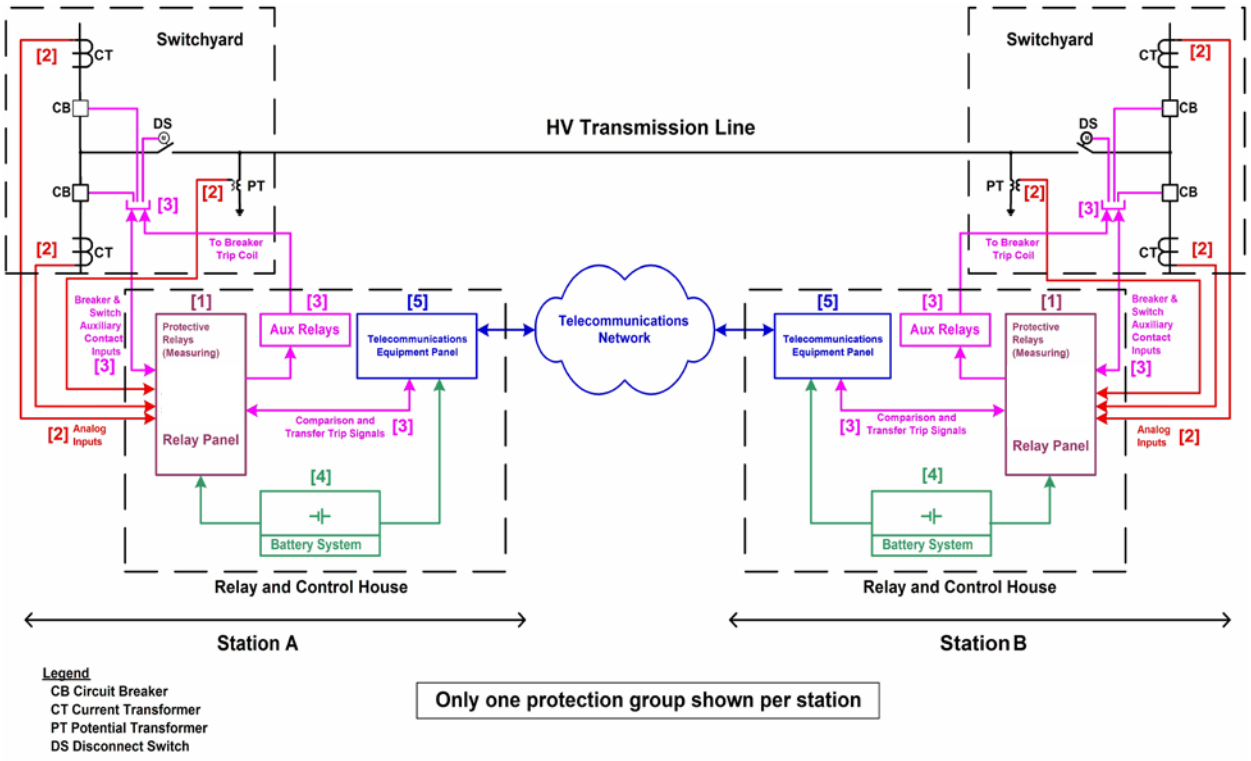
16. “Essentials of Statistics for Business and Economics” Anderson, Sweeney, Williams, 2003
17. “Introduction to Statistics and Data Analysis” - Second Edition, Peck, Olson, Devore, 2005
18. “Statistical Analysis for Business Decisions” Peters, Summers, 1968
19. “Considerations for Maintenance and Testing of Autoreclosing Schemes,” NERC System Analysis and Modeling Subcommittee and NERC System Protection and Control Subcommittee, November 2012

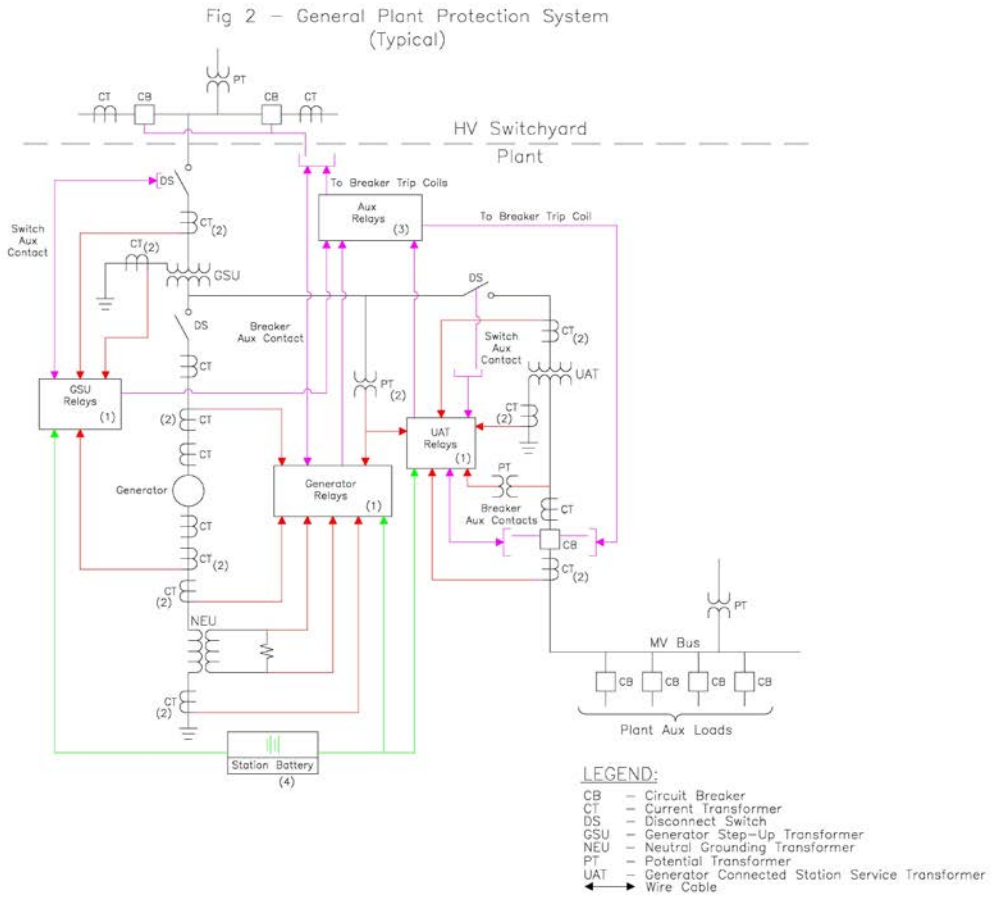
Figures

Figure 1: Typical Transmission System



For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

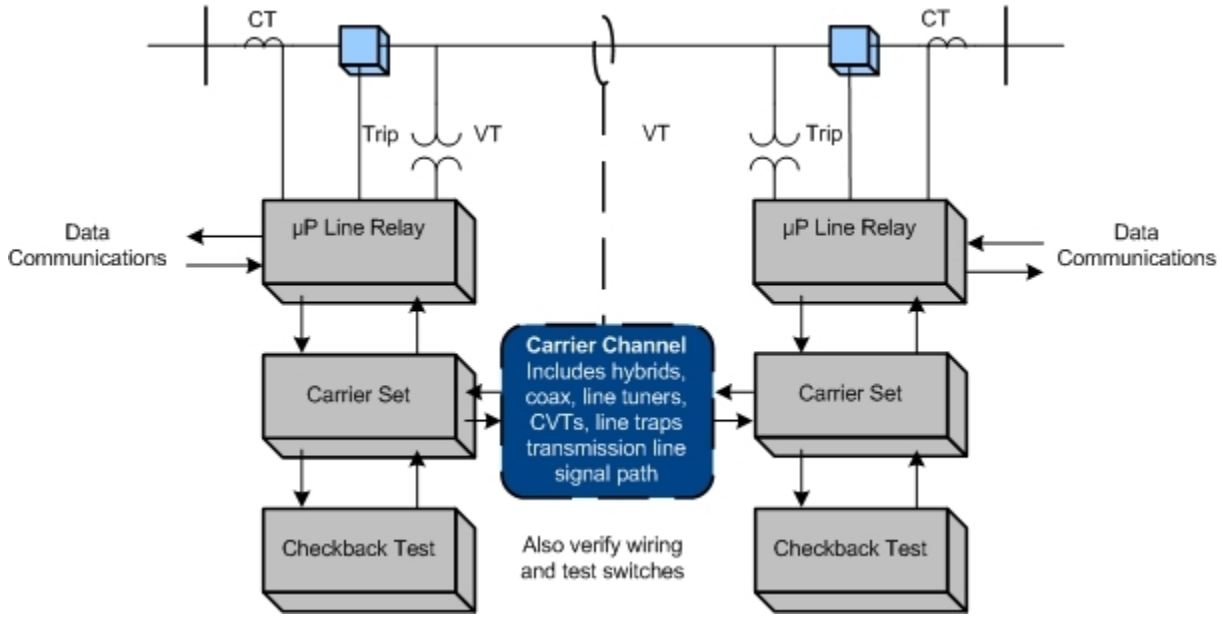
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

Additional information can be found in References

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

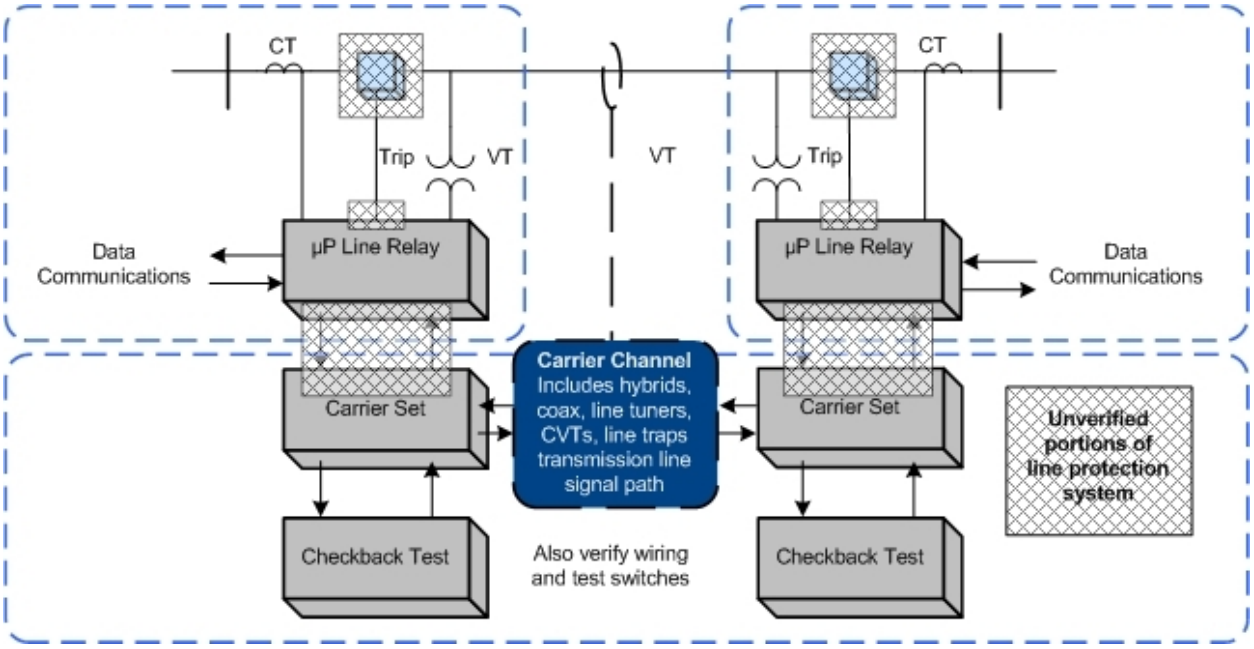
1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One

effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-4 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

Protection System Maintenance Standard Drafting Team

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Directives

Project 2007-17.4 – PRC-005 Order 803 Directive

April 22, 2015

Project 2007-17.4 – PRC-005 Order 803 Directive		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
In Order No. 803, FERC approved Standard PRC-005-3 and, in Paragraph 31, directed NERC to: "...direct that, pursuant to section 215(d)(5) of the FPA, NERC develop modifications to PRC-005-3 to include supervisory devices associated with auto-reclosing relay schemes to which the Reliability Standard applies. Further, we clarify that NERC's proposal regarding the scope of supervisory devices is an acceptable approach to satisfy the Commission directive. Specifically, NERC proposed in its NOPR comments, and we find acceptable, that the scope of the supervisory devices to be encompassed in the Reliability Standard are those providing voltage supervision, supervisory inputs associated with selective auto-reclosing, and sync-check relays that are part of a reclosing scheme covered by PRC-005-3."	FERC Order 803 approving Reliability Standard PRC-005-3, P Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance	The Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT) proposed revision of the standard specific defined terms "Automatic Reclosing" and "Component Type" as follows: Automatic Reclosing – Includes the following Components: • Reclosing relay • Supervisory relay(s) – relay(s) that perform voltage and/or sync check functions that enables or disables operation of the reclosing relay • Voltage sensing devices associated with the supervisory relay(s) • Control circuitry associated with the reclosing relay or supervisory relay(s) Component Type –

Project 2007-17.4 – PRC-005 Order 803 Directive		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		• Any one of the five specific elements of a Protection System. • Any one of the two four specific elements of Automatic Reclosing. • Any one of the two specific elements of Sudden Pressure Relaying. The Rationales for "Automatic Relaying" and "Component Type" were also revised to reflect the proposed revisions to the defined terms above. Tables 4-1 and 4-2 were updated by adding "supervisory relay(s)" as appropriate. A new Table 4-3 was added to address maintenance activities and intervals for Automatic Reclosing with supervisory relays. No substantive revisions are being proposed for the Requirements of the standard. The only revisions to Requirements R1 and R3 included updating the Table numbering to reflect the addition of Table 4-3. The VSLs were updated to reflect the Requirement language for R1 and R3. All references to table numbering throughout the standard have also been corrected to reflect the addition of Table 4-3. This version of PRC-005 used PRC-005-5 developed under Project 2014-01 as the starting point for revisions to address the directive.

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Implementation Plan

Project 2007-17.4 PRC-005 FERC Order No. 803 Directive PRC-005-6

Standards Involved

Approval:

- PRC-005-6 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-5 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
- PRC-005-4 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
- PRC-005-3 (ii) Protection System and Automatic Reclosing Maintenance
- PRC-005-3 (i) Protection System and Automatic Reclosing Maintenance
- PRC-005-3 Protection System and Automatic Reclosing Maintenance
- PRC-005-2 (ii) Protection System Maintenance
- PRC-005-2 (i) Protection System Maintenance
- PRC-005-2 Protection System Maintenance
- PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
- PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

Prerequisite Approvals:

N/A

Background:
In Order No. 803, FERC approved Standard PRC-005-3 and, in Paragraph 31, directed NERC to:

"...develop modifications to PRC-005-3 to include supervisory devices associated with auto-reclosing relay schemes to which the Reliability Standard applies. Further, we clarify that NERC's proposal regarding the scope of supervisory devices is an acceptable approach to satisfy the Commission directive. Specifically, NERC proposed in its NOPR comments, and we find acceptable, that the scope of the supervisory devices to be encompassed in the Reliability Standard are those providing voltage supervision, supervisory inputs associated with selective auto-reclosing, and sync-check relays that are part of a reclosing scheme covered by PRC-005-3."

This Implementation Plan adds:

- The implementation of changes relating to maintenance and testing of supervisory relays and associated voltage sensing devices related to Automatic Reclosing.
- The phased implementation approach included in the approved PRC-005-2 and proposed PRC-005-2(i) will remain as-is.
- This implementation schedule lays out the implementation timeline for the currently effective PRC-005-2 and proposed PRC-005-2(i), and combines the implementation plans for the approved PRC-005-3 and all subsequent pending PRC-005 versions (PRC-005-2(ii), PRC-005-3(i), PRC-005-3(ii), PRC-005-4 and PRC-005-5), making all versions from PRC-005-3 onwards effective on the same day PRC-005-6 becomes effective. The effective dates for the various phases specified in PRC -005-3 and each subsequent version of PRC-005 will align with the effective dates for those phases included in the PRC-005-6 Implementation Plan. For the pending versions that do not entail phased implementation, the versions will become effective on the date PRC-005-6 first becomes effective.
- Notwithstanding any order to the contrary, PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4 and PRC-005-5 will not become effective, and PRC-005-2 will remain in effect and not be retired until the effective date of the PRC-005-6 standard under this implementation plan.[1]

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry forward requirements from PRC-005-2, PRC-005-2(i), PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4 and PRC-005-5, establish minimum maintenance activities for Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Types as well as the maximum allowable maintenance intervals for these maintenance activities.

[1] In jurisdictions where previous versions of PRC-005 have not yet become effective according to their implementation plans (even if approved by order), this implementation plan and the PRC-005-6 standard supersedes and replaces the implementation plans and standards for PRC-005-2(i), PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4, and PRC-005-5.

2. The maintenance activities established in the various PRC-005 versions may not be presently performed by some registered entities and the established maximum allowable intervals may be shorter than those currently in use by some entities. Therefore, registered entities may not be presently performing a maintenance activity or may be using longer intervals than the maximum allowable intervals established in the PRC-005 standards. For these registered entities, it is unrealistic to become immediately compliant with the new activities or intervals. Further, registered entities should be allowed to become compliant in such a way as to facilitate a continuing PRC-005 maintenance program. The registered entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
3. The implementation schedule set forth below carries forward the implementation schedules contained in PRC-005-2 and proposed PRC-005-2(i), and combines the implementation schedules for PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4 and PRC-005-5. In addition, the implementation schedule includes changes needed to address the addition of Automatic Reclosing supervisory relays and associated voltage sensing devices in PRC-005-6.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets all of the requirements of the effective PRC-005-2, or its combined successor standards, in accordance with this implementation plan.

While registered entities are implementing the requirements of PRC-005-2 or its combined successor standards, each registered entity must be prepared to identify:

- All of its applicable Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components, and
- Whether each component has last been maintained according to PRC-005-2 (or its combined successor standards), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

Effective Date

PRC-005-6 shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-2 and shall be applicable to a registered entity's Protection System Component maintenance activities not yet transitioned to PRC-005-2. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of March 31, 2027 or as otherwise made effective pursuant to the laws applicable to such Electric Reliability Organization (ERO) governmental authorities; or, in those jurisdictions where no regulatory approval is required, at midnight of March 31, 2027.

PRC-005-2 and PRC-005-2(i) shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-6, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter from the date of Board of Trustees' adoption.

If approved by FERC prior to the approval of PRC-005-6, PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4 and PRC-005-5 shall be retired on the date immediately prior to the first day of the first calendar quarter following regulatory approval of PRC-005-6.

Implementation Plan for Definitions:

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, the Glossary definition will be removed from the individual standard and added to the Glossary. The definitions of terms used only in the standard will remain in the standard.

Glossary Definition:

- None

Definitions of Terms Used in the Standard:

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Supervisory relay(s) – relay(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay
- Voltage sensing devices associated with the supervisory relay(s)
- Control circuitry associated with the reclosing relay or supervisory relay(s)

Component Type –

- Any one of the five specific elements of a Protection System.

- Any one of the four specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

Implementation Plan for New or Revised Definitions:

The revised definitions (Automatic Reclosing, Component, and Countable Event) become effective upon the effective date of PRC-005-6.

Implementation Plan for PRC-005-2 and PRC-005-6

Requirements R1, R2, and R5:

PRC-005-2: For Protection System Components, entities shall be 100% compliant on April 1, 2015 or, in those jurisdictions where no regulatory approval is required, on January 1, 2015 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

PRC-005-6: For Automatic Reclosing Components, Sudden Pressure Relaying Components, and Dispersed Generation Resources, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-6 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-6 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

PRC-005-2:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
   - The entity shall be 100% compliant on October 1, 2015, or in those jurisdictions where no regulatory approval is required, on July 1, 2016, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:

   - The entity shall be 100% compliant on April 1, 2017 or, in those jurisdictions where no regulatory approval is required, on January 1, 2017or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:

   - The entity shall be at least 30% compliant on April 1, 2016 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on January 1, 2016 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on April 1, 2017 or, in those jurisdictions where no regulatory approval is required, on January 1, 2017 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on April 1, 2018 or, in those jurisdictions where no regulatory approval is required, on January 1, 2018 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:

   - The entity shall be at least 30% compliant on April 1, 2017 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on January 1, 2017 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on April 1, 2019 or, in those jurisdictions where no regulatory approval is required, on January 1, 2019 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on April 1, 2021 or, in those jurisdictions where no regulatory approval is required, on January 1, 2021 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on April 1, 2019 or, in those jurisdictions where no regulatory approval is required, on January 1, 2019 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on April 1, 2023 or, in those jurisdictions where no regulatory approval is required, on January 1, 2023 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on April 1, 2027 or, in those jurisdictions where no regulatory approval is required, on January 1, 2027 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

PRC-005-6:

1. For Automatic Reclosing Components, Sudden Pressure Relaying Components, and Dispersed Generation Resources maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):
   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-6 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-6 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-6 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-6, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-6 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-6 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
2. For Automatic Reclosing Components, Sudden Pressure Relaying Components, and Dispersed Generation Resources maintenance activities, with maximum allowable intervals of twelve (12) calendar years, as established in Table 4-1, 4.2(a), or 4.2(b):
   - The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-6 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two

(72) months following NERC Board of Trustees' adoption of PRC-005-6 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-6 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-6 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-6 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-6 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment March 12 – April 10, 2015.

Description of Current Draft

This version of PRC-005 is posted for a 45-day concurrent comment and ballot period to address directives from FERC Order No. 803, addressing Automatic Reclosing. Specifically, supervisory relays, associated voltage sensing devices, and associated control circuitry were added.

Anticipated Actions	Anticipated Dates
45-day Formal Comment Period with Parallel Ballot	May 2015 – July 2015
Final ballot	July 2015
BOT adoption	August 2015

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Automatic Reclosing (see Section 6 of the Standard)

A. Introduction

1. **Title:** **Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**

2. **Number: PRC-005-6~~5~~**

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

   4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

   4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

   4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

   4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, except for generators identified through Inclusion I4 of the BES definition, including:

   4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

   4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

   4.2.5.3 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

4.2.7 Automatic Reclosing[1], including:

4.2.7.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.[2]

4.2.7.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.7.3 Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. **Effective Date:** See the Implementation Plan for this standard.

6. **Definitions Used in this Standard:**

[1] Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Supervisory relay(s) – relay(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay
- Voltage sensing devices associated with the supervisory relay(s)
- Control circuitry associated with the reclosing relay or supervisory relay(s)

Rationale for revisions to Automatic Reclosing: To address directives from FERC Order No. 803 addressing Automatic Reclosing, the definition for Automatic Reclosing was revised to add supervisory relays, the associated voltage sensing devices, and the associated control circuitry.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the ~~two~~ four specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for revisions to Component Type: With the revision of the definition of Automatic Reclosing, there are four specific elements of this definition, rather than two as stated in the prior version.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table

3, Tables 4-1 through 4-3~~2~~, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station ~~dc~~ DC supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3~~2~~, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented PSMP~~rotection System Maintenance Program~~ in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station ~~dc~~ DC supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3~~2~~, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3~~2~~, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the PSMP~~rotection System Maintenance Program~~ for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance

Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated PSMP~~rotection System Maintenance Program~~, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-~~3~~2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-~~2~~3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-~~2~~3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-~~2~~3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-~~2~~3, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005~~-4~~ Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2015~~4~~)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)
4. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities* – Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing (October 31, 2014)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New.
1	February 7, 2006	Adopted by NERC Board of Trustees	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.
1a	February 17, 2011	Adopted by NERC Board of Trustees	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17.
1b	November 5,	Adopted by NERC Board of	Interpretation of R1, R1.1, and

Version	Date	Action	Change Tracking
	2009	Trustees	R1.2 developed by Project 2009-10.
1b	February 3, 2012	FERC Order approving revised definition of "Protection System"	Per footnote 8 of FERC's order, the definition of "Protection System" supersedes interpretation "b" of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013). *See N. Amer. Elec. Reliability Corp.*, 138 FERC ¶ 61,095 (February 3, 2012).
1.1b	May 9, 2012	Adopted by NERC Board of Trustees	Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner's responsibility.
2	November 7, 2012	Adopted by NERC Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0.
2	October 17, 2013	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing Standards" section. (no change to standard version number)
2	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number).
2(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.

Version	Date	Action	Change Tracking
2(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS.
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs.
3	February 12, 2014	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of "Unresolved Maintenance Issue" and "Protection System Maintenance Program". The changes will be reflected in the definitions section of PRC-005-3 for "Unresolved Maintenance Issue" and in the NERC Glossary of Terms for "Protection System Maintenance Program". (no change to standard version number)
3	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number).
3(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.
3(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS.
4	November 13, 2014	Adopted by NERC Board of Trustees	Added Sudden Pressure Relaying in response to FERC Order No. 758.
5	TBD		Applicability section revised by Project 2014-01 to clarify application of Requirements to

Version	Date	Action	Change Tracking
			BES dispersed power producing resources.
6	TBD		Revised to add supervisory relays to Automatic Reclosing in accordance with the directives in FERC Order 803.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[3]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[3]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ~~ac~~ AC measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent AC~~ac~~ measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station ~~dc~~ DC Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station ~~dc~~ DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station ~~dc~~ DC supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station ~~dc~~ DC supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station ~~dc~~ DC Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station ~~dc~~ DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station ~~dc~~ DC Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station ~~dc~~ DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station ~~dc~~ DC supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station ~~dc~~ DC supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station ~~dc~~ DC Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station ~~dc~~ DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station ~~dc~~ DC Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station ~~dc~~ DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station ~~dc~~ DC supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station ~~dc~~ DC supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station ~~dc~~ DC Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station ~~dc~~ DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station ~~dc~~ DC Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station ~~dc~~ DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station ~~dc~~ DC supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station ~~dc~~ DC supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based ~~dc~~ DC supply
	6 Calendar Years	Verify that the ~~dc~~ DC supply can perform as manufactured when ~~ac~~ ACpower is not present.

Table 1-4(e) Component Type – Protection System Station ~~dc~~ DC Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System ~~dc~~ DC supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station ~~dc~~ DC supply voltage.

Table 1-4(f) Exclusions for Protection System Station ~~dc~~ DC Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station ~~dc~~ DC supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station ~~dc~~ DC supply voltage is required.
Any battery based station ~~dc~~ DC supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station ~~dc~~ DC supply with unintentional ~~dc~~ DC ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional ~~dc~~ DC grounds is required.
Any station ~~dc~~ DC supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station ~~dc~~ DC supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station ~~dc~~ DC supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station ~~dc~~ DC supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-~~23~~, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-~~23~~, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ~~ac~~ AC measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System ~~dc~~ DC supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System ~~dc~~ DC supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing and Supervisory Relay Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay or supervisory relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. For microprocessor supervisory relays: • Verify acceptable measurement of power system input values.
Monitored microprocessor reclosing relay or supervisory relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). For supervisory relay: • Voltage waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.	12 Calendar Years	Verify: • Settings are as specified. Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. For supervisory relays: • Verify acceptable measurement of power system input values.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing and Supervisory Relay Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Monitored microprocessor reclosing relay or supervisory relay with preceding row attributes and the following: • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). For supervisory relay: • AC measurements are continuously verified by comparison to an independent AC measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that are NOT an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that ARE an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 4-3 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Voltage Sensing Devices Associated with Supervisory Relays		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that voltage signal values are provided to the supervisory relays.
Voltage sensing devices that are connected to microprocessor supervisory relays with AC measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent AC measurement source, with alarming for unacceptable error or failure. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3~~2~~, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment March 12 – April 10, 2015.

Description of Current Draft

This version of PRC-005 is posted for a 45-day concurrent comment and ballot period to address directives from FERC Order No. 803, addressing Automatic Reclosing. Specifically, supervisory relays, associated voltage sensing devices, and associated control circuitry were added.

Anticipated Actions	Anticipated Dates
45-day Formal Comment Period with Parallel Ballot	May 2015 – July 2015
Final ballot	July 2015
BOT adoption	August 2015

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Automatic Reclosing (see Section 6 of the Standard)

A. Introduction

1. **Title:** **Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**

2. **Number: PRC-005-6**

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

   4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

   4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

   4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

   4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, except for generators identified through Inclusion I4 of the BES definition, including:

   4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

   4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

   4.2.5.3 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

4.2.7 Automatic Reclosing[1], including:

4.2.7.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.[2]

4.2.7.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.7.3 Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. **Effective Date:** See the Implementation Plan for this standard.

6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Supervisory relay(s) – relay(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay

Rationale for revisions to Automatic Reclosing: To address directives from FERC Order No. 803 addressing Automatic Reclosing, the definition for Automatic Reclosing was revised to add supervisory relays, the associated voltage sensing devices, and the associated control circuitry.

[1] Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

- Voltage sensing devices associated with the supervisory relay(s)
- Control circuitry associated with the reclosing relay or supervisory relay(s)

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the four specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for revisions to Component Type: With the revision of the definition of Automatic Reclosing, there are four specific elements of this definition, rather than two as stated in the prior version.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station DC supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented PSMP in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station DC supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2,

which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the PSMP for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated PSMP, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2015)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)
4. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities* – Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing (October 31, 2014)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New.
1	February 7, 2006	Adopted by NERC Board of Trustees	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.
1a	February 17, 2011	Adopted by NERC Board of Trustees	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17.

Version	Date	Action	Change Tracking
1b	November 5, 2009	Adopted by NERC Board of Trustees	Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10.
1b	February 3, 2012	FERC Order approving revised definition of "Protection System"	Per footnote 8 of FERC's order, the definition of "Protection System" supersedes interpretation "b" of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013). *See N. Amer. Elec. Reliability Corp.*, 138 FERC ¶ 61,095 (February 3, 2012).
1.1b	May 9, 2012	Adopted by NERC Board of Trustees	Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner's responsibility.
2	November 7, 2012	Adopted by NERC Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0.
2	October 17, 2013	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing Standards" section. (no change to standard version number)
2	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number).
2(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.

Version	Date	Action	Change Tracking
2(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS.
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs.
3	February 12, 2014	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of “Unresolved Maintenance Issue” and “Protection System Maintenance Program”. The changes will be reflected in the definitions section of PRC-005-3 for “Unresolved Maintenance Issue” and in the NERC Glossary of Terms for “Protection System Maintenance Program". (no change to standard version number)
3	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number).
3(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.
3(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS.
4	November 13, 2014	Adopted by NERC Board of Trustees	Added Sudden Pressure Relaying in response to FERC Order No. 758.

Version	Date	Action	Change Tracking
5	TBD		Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.
6	TBD		Revised to add supervisory relays to Automatic Reclosing in accordance with the directives in FERC Order 803.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[3]	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[3]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent AC measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent AC measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station DC Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station DC supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station DC supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station DC Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station DC Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station DC supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station DC supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station DC Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station DC Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station DC supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station DC supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station DC Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station DC Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station DC supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station DC supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station DC supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based DC supply
	6 Calendar Years	Verify that the DC supply can perform as manufactured when ACpower is not present.

Table 1-4(e) Component Type – Protection System Station DC Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System DC supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station DC supply voltage.

Table 1-4(f) Exclusions for Protection System Station DC Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station DC supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station DC supply voltage is required.
Any battery based station DC supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station DC supply with unintentional DC ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional DC grounds is required.
Any station DC supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station DC supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station DC supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station DC supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent AC measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System DC supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System DC supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing and Supervisory Relay Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay or supervisory relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. For microprocessor supervisory relays: • Verify acceptable measurement of power system input values.
• Monitored microprocessor reclosing relay or supervisory relay with the following: Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). For supervisory relay: • Voltage waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.	12 Calendar Years	Verify: • Settings are as specified. Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. For supervisory relays: • Verify acceptable measurement of power system input values.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing and Supervisory Relay Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Monitored microprocessor reclosing relay or supervisory relay with preceding row attributes and the following: • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). For supervisory relay: • AC measurements are continuously verified by comparison to an independent AC measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that are NOT an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that ARE an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 4-3 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Voltage Sensing Devices Associated with Supervisory Relays		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that voltage signal values are provided to the supervisory relays.
Voltage sensing devices that are connected to microprocessor supervisory relays with AC measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent AC measurement source, with alarming for unacceptable error or failure. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
Valerie.Agnew@nerc.net

For questions about this form or for assistance in completing the form, call Valerie Agnew at 404-446-2566.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	PRC-005-6		
Date Submitted:	May 21, 2015		
SAR Requester Information			
Name:	Charles Rogers		
Organization:	Protection System Maintenance Standard Drafting Team		
Telephone:	517-788-0027	E-mail:	Charles.Rogers@cmsenergy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
In Order No. 803, FERC approved Standard PRC-005-3 and, in Paragraph 31, directed that: "...pursuant to section 215(d)(5) of the FPA, NERC develop modifications to PRC-005-3 to include supervisory devices associated with auto-reclosing relay schemes to which the Reliability Standard applies. Further, we clarify that NERC's proposal regarding the scope of supervisory devices is an acceptable approach to satisfy the Commission directive. Specifically, NERC proposed in its NOPR comments, and we find acceptable, that the scope of the supervisory devices to be encompassed in the Reliability Standard are those providing voltage supervision, supervisory inputs associated with selective auto-reclosing, and sync-check relays that are part of a reclosing scheme covered by PRC-005-3."

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The SDT shall consider modifications, as needed, to address the FERC directive contained in Order 803 resulting from the Commission's consideration of PRC-005-3. The Supplementary Reference Document (provided as a technical reference for PRC-005-3) should also be modified to provide the rationale for the maintenance activities and intervals within the revised standard, as well as to provide application guidance to industry.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements, standard specific definitions standard(s), and advisory guidance to address the directives in FERC Order 803.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standard Drafting Team (SDT) shall modify NERC Standard PRC-005-3 to explicitly address the directive in Order 803. The SDT shall also consider changes to the standard and supporting documents that provide consistency and alignment with other Reliability Standards.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to address the directive in FERC Order 803. The SDT will develop requirement(s) to include supervisory devices associated with automatic reclosing relay schemes to which the Reliability Standard applies. The SDT may elect to propose revisions to the standard regarding the scope of supervisory devices as an acceptable approach to satisfy the Commission directive, as proposed in the NOPR comments submitted by NERC. Specifically, NERC proposed that the scope of the supervisory devices to be encompassed in the Reliability Standard are those providing voltage supervision, supervisory inputs associated with selective automatic reclosing, and synchronism check relays that are part of a reclosing scheme covered by PRC-005-3. The SDT shall also: 1. Revise the Implementation Plans for PRC-002i, PRC-005-2ii, PRC-005-3, PRC-005-3i, PRC-005-3ii, PRC-005-4 and PRC-005-5 as needed to facilitate consistent and systematic implementation. 2. Modify the informative Supplementary Reference Document (provided as a technical reference for PRC-005-3) as necessary to provide application guidance to industry.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions	
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒ Distribution Provider	Delivers electrical energy to the End-use customer.
☒ Generator Owner	Owns and maintains generation facilities.
☐ Generator Operator	Operates generation unit(s) to provide real and reactive power.
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
	1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
	2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
	3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
	4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Draft White Paper

Proposed Revisions to the Applicability of NERC Reliability Standards ~~NERC Standards Applicability~~ to Dispersed Generation Resources

Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Drafting Team

~~December 11, 2014~~

June 12, 2015

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1 Executive Summary

The purpose of this White Paper is to provide background and technical rationale for proposed revisions to the applicability of several North American Electric Reliability Corporation (NERC) Reliability Standards, and in some cases the standard requirements. The goal of the NERC Project 2014-01 Standards Applicability for Dispersed Generation Resources[1] standard drafting team (SDT) is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System (BPS), as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Authority (FERC) in 2014[2], the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The SDT reviewed all standards that apply to GOs and GOPs[3] and determined how each standard requirement should be appropriately applied to dispersed power producing resources, categorized as follows:

- The existing standard language was appropriate when applied to dispersed power producing resources and does not need to be addressed;
- The existing standard language was appropriate when applied to dispersed power producing resources but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed power producing resources; and
- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed power producing resources. This could be accomplished through the a~~A~~pplicability s~~S~~ection of the standard in most cases or, if required, through narrowly~~-~~ tailored changes to the individual requirements.

From this review, the SDT determined that three (3) Reliability Standards required immediate attention to clarify the applicability of the Reliability Standards to dispersed power producing resources for the benefit of industry stakeholders. These standards are:

- PRC-004 (relevant versions)[4];
- PRC-005 (relevant versions)[5]; and
- VAR-002 (relevant versions).

The SDT recognized that many other standards[6] required further review to determine the necessity and the type of clarification or guidance for the applicability to dispersed power producing resources. This

[1] Although the BES definition uses the term "dispersed power producing resources," the SAR and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.
[2] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014.
[3] See Appendix A.
[4] Reliability Standard PRC-004 was revised as part of Project 2010-05.1 Protection Systems: Misoperations.
[5] Reliability Standard PRC-005 was revised as part of Project 2007-17.3 – Protection System Maintenance and Testing – Phase 3.
[6] See Appendix B.

necessity is based on how each standard requirement, as written, would apply to dispersed power producing resources and the individual generating units at these facilities, considering the now currently-~~enforced~~effective BES definition. The proposed resolutions target the applicability of the standard or target specific individual requirements. There are additional methods to ensure consistent applicability throughout the Regions, including having guidance issued by NERC through Reliability Standard Audit Worksheet (RSAW) language revisions. These tools, among others, have been be considered and employed by the SDT throughout the drafting effort.

The White Paper includes: 1) description of the history of standards applicability to dispersed power producing resources; 2) identification of circumstances and practices that are unique to dispersed power producing resources; and 3) determination of the priority to address standards, supported by corresponding technical justification.

It is the intent of the SDT to modify this document over the course of this project to document the SDT's rationale and technical justification for each standard until the work of the SDT is complete. The SDT considers the sections of the White Paper that address the high-priority standards to be in final draft form. The SDT may provide further revisions to the remainder of the White Paper.

2 Purpose

The purpose of this White Paper is to provide background and technical rationale for proposed revisions to the applicability of several Reliability Standards[7] or requirements that apply to GOs and/or GOPs. The goal of the proposed applicability changes is to provide the GOs and GOPs of dispersed generation resources with clarity regarding their responsibility for requirements that impact the reliability of the BPS, as the characteristics of operating dispersed generation can be unique. The SDT seeks to provide clarity through the method most appropriate for each standard, such as by: (1) revising applicability language in the standard; (2) revising language in the requirements to address changes to applicability; (3) recommending changes to the RSAW associated with the standard; or (4) recommending a reliability guideline or reference document.

This document describes the design, operational characteristics, and unique features of dispersed power producing resources. The recommendations identified in this document consider the Purpose and Time Horizon of the standards and requirements, as well as the avoidance of applying requirements in a manner that has no significant effect on reliability.[8] This document provides justification of, and proposes revisions to, the applicability of the Reliability Standards and requirements, both existing and in development, and should be considered guidance for future standard development efforts. However, please note that the recommendations provided in this paper are subject to further review and revision.

Note that while this White Paper may provide examples of dispersed power producing resources, the concepts presented are not specific to any one technology. The SDT in general has referenced the BES Reference Document, which also refers to "dispersed power producing resources." Although the BES definition uses the term "dispersed power producing resources," the Standard Authorization Request (SAR) and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.

[7] Note that "Reliability Standard" is defined in the NERC Glossary as "approved by FERC," but that the SDT reviewed approved standards, as well as revisions to standards proposed in other projects.
[8] *North American Electric Reliability Corporation,* 138 FERC ¶ 61,193 at P 81 (2012).

3 Background

Industry stakeholders submitted a SAR to the NERC Standards Committee, requesting that the applicability of Reliability Standards or the requirements of Reliability Standards be revised to ensure that the Reliability Standards are not imposing requirements on dispersed generation resource components that are unnecessary or counterproductive to the reliability of the BPS. The SDT's focus has been to ensure that Reliability Standards are applied to dispersed power producing resources to support an effective defense-in-depth strategy and an adequate level of reliability for the interconnected BPS.

For purposes of this effort, dispersed power producing resources are those individual resources that aggregate to a total capacity greater than 75 MVA gross nameplate rating, and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This request is related to the approved definition of the BES from Project 2010-17,[9] which resulted in the inclusion of distinct components of dispersed generation resources.

3.1 BES Definition

The BES definition[10] includes the following inclusion criterion addressing dispersed generation resources:

> *I4. Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:*
>
> *a) ~~T~~the individual resources~~,~~ and*
>
> *b) ~~T~~the system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.*

The *BES Definition Reference Document*[11] includes a description of what constitutes a dispersed generation resource:

> *"Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to: solar, geothermal, energy*
>
> *storage, flywheels, wind, micro-turbines, and fuel cells."*

[9] http://www.nerc.com/pa/Stand/Pages/Project2010-17_BES.aspx

[10] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014. http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

[11] Bulk Electric System Definition Reference Document, Version 2, April 2014. http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_reference_document_20140325_final_clean.pdf.

3.2 Dispersed Power Producing Resources

Dispersed power producing resources are often considered to be variable energy resources such as wind and solar. This description is not explicitly stated in the BES definition; however, NERC and FERC characterize variable generation in this manner regarding the purpose of Inclusion I4 of the definition.[12]. Therefore, the SDT is considering the reliability impacts of variable generation that depends on a primary fuel source ~~which~~that varies over time and cannot be stored.[13] Reliably integrating high levels of variable resources – wind, solar, ocean, and some forms of hydro – into the BPS require significant changes to traditional methods used for system planning and operation.[14] While these resources provide challenges to system operation, these resources are instrumental in meeting government-established renewable portfolio standards and requirements that are based on vital public interests.[15]

3.2.1 Design Characteristics

For dispersed power producing resources to be economically viable, it is necessary for the equipment to be geographically dispersed. The generating capacity of individual generating modules can be as small as a few hundred watts to as large as several megawatts. Factors leading to this dispersion requirement include:

- Practical maximum size for wind generators to be transported and installed at a height above ground to optimally utilize the available wind resource;
- Spacing of wind generators geographically to avoid interference between units;
- Solar panel conversion efficiency and solar resource concentration to obtain usable output; and
- Cost-effective transformation and transmission of electricity.

The utilization of small generating units results in a large number of units (e.g., several hundred wind generators or several million solar panels) installed collectively as a single facility that is connected to the Transmission system.

Dispersed power producing resources interconnected to the transmission system typically have a control system at the group level that controls voltage and power output of the Facility. The control system is capable of recognizing the capability of each individual unit or inverter to appropriately distribute the contribution required of the Facility across the available units or inverters. The variable generation control system must also recognize and account for the variation of uncontrollable factors such as wind speed and solar irradiance levels. Thus, for some standards discussed in this paper it is appropriate to apply requirements at the plant level rather than the individual generating unit.

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[12] NERC December 13, 2013 filing, page 15 (FERC Docket No. RD14-2); NERC December 13, 2013 filing, page 17 (FERC Docket No. RD14-2); NERC January 25, 2012 filing, page 18 (FERC Docket No. RD14-2), FERC Order Approving Revised Definition, Docket No. RD14-2-000, Issued March 20, 2014.

[13] "*Electricity Markets and Variable Generation Integration*," WECC, January 6, 2011.

[14] "*Accommodating High Levels of Variable Generation*," NERC, April, 2009. http://www.nerc.com/files/ivgtf_report_041609.pdf

[15] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 335, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

3.2.2 Operational Characteristics

Dispersed power producing resources often rely on a variable energy source (wind, for example) that is not able to be stored. Because of this, a Facility operator cannot provide a precise forecast of the expected output to a Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC); however, short-term forecasting capability is improving and thus reducing uncertainty.[16] The forecasting and variable operating conditions are well understood by BAs, TOPs, and RCs as evidenced by the successful operation of these generating resources over the years. Dispersed generation resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g. voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities' design.

Many older dispersed power producing resources are limited in their ability to provide essential reliability services. However, due to technological improvements, newer dispersed generation resources are capable of providing system support for voltage and frequency. For efficiency, the facilities are designed to provide the system requirements at the point of interconnection to the transmission system.

3.2.3 Reliability Impact

A dispersed power producing resource is typically made up of many individual generating units. In most cases, the individual generating units are similar in design and from one manufacturer. The aggregated capability of the Facility may in some cases contribute significantly to the reliability of the BPS. As such, there can be reliability benefits from ensuring the equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in certain applicable NERC standards. When evaluated individually, however, the individual generating units often do not provide a significant impact to BPS reliability, as the unavailability or failure of any one individual generating resource may have a negligible impact on the aggregated capability of the Facility. The SDT acknowledges that FERC addressed the question of whether individual resources should be included in the BES definition in Order Nos. 773 and 773-A and concluded that individual wind turbine generators should be included as part of the BES. The SDT is not challenging this conclusion, but rather is addressing the applicability of standards on a requirement-by-requirement basis as necessary to account for the unique characteristics of dispersed generation. Thus, the applicability of requirements to individual generating units may be unnecessary except in cases where a common mode issue exists that could lead to a loss of a significant number of units or the entire Facility in response to a transmission system event.

3.3 Drafting Team Efforts

The SDT approached this project in multiple phases. First, after a thorough discussion of the new definition of the BES, the SDT reviewed each standard, as shown in Appendix A, at a high level to recommend changes that would promote consistent applicability for dispersed power producing resources through the entire set of Reliability Standards. This review provided the type of changes proposed, the justification for the changes, and the priority of the changes. The SDT documented its review in this

[16] "*Electricity Markets and Variable Generation Integration*," WECC, January 6, 2011. https://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf

White Paper, which will continue to be updated throughout the SDT efforts. The second phase, currently in progress, includes revising standards where necessary and supporting the balloting and commenting process.

3.3.1 Scope of Standards Reviewed

Initially, the focus of the standards review was on standards and requirements applicable to GOs and GOPs. However, during discussions, a question was raised to the SDT regarding whether consideration is necessary for other requirements that affect the interaction of a Balancing Authority (BA), Transmission Operator (TOP), or Reliability Coordinator (RC) with individual BES Elements. For example, a requirement that states, "an RC shall monitor BES Elements" may unintentionally affect the RC operator due to the revised BES definition. As such, the SDT took a high-level look at all standards adopted by the NERC Board of Trustees (Board) or approved by FERC to ensure this issue was not significant.

All standards that were reviewed are listed in Appendix A along with the status of the standards as of December 11, 2014. The fields in Appendix A include the following:

- List of standards (grouped by approval status);
- Approval status of the standards (status types listed below)~~which include~~:
  - Subject to Enforcement
  - Subject to Future Enforcement
  - Filed and Pending Regulatory Approval
  - Pending Regulatory Filing
  - Designated for Retirement (~~2~~ two standards~~—-~~MOD-024-1 and MOD-025-1~~—~~ officially listed as Filed and Pending Regulatory Approval but will be superseded by MOD-025-2)
  - In Concurrent Active Development~~concurrent active development~~; and
- Indication of change or additional review necessary~~.~~

The SDT also reviewed, at a high-level, any approved regional standards. In cases where a change is recommended to a regional standard, the SDT will notify the affected Region. In addition, the SDT is prepared to provide recommendations to other active NERC standard development efforts, where appropriate.

Status	Number of Standards	Number of Standards to be Addressed (Standard, RSAW, Guidance or Further Review)
NERC Standards	**166**	**27**
Subject to Enforcement	101	12
Subject to Future Enforcement	20	5
Pending Regulatory Approval	28	4
Pending Regulatory Filing	7	0
Designated for Retirement	2	0
Proposed for Remand	8	6
Region-specific Standards (*Out of Scope)	**17**	**4**
Subject to Enforcement	15	3
Subject to Future Enforcement	2	1
Pending Regulatory Approval	0	0
Grand Total	**183**	**31**

3.3.2 Reliability Objectives

The SDT used the following ~~R~~reliability ~~O~~objectives to review the standards:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC ~~Standards~~standards;
- The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand;
- Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably;
- Plans for Emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented;
- Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems;
- Personnel responsible for planning and operating interconnected bulk power systems shall be trained~~,~~ and qualified~~,~~ and have the responsibility and authority to implement actions;
- The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis; and
- Bulk power systems shall be protected from malicious physical or cyber attacks.

3.3.3 Prioritization Methodology

The SDT established a prioritization to review and modify applicability changes recommended to NERC standards and requirements. The SDT evaluated each requirement to identify the appropriate applicability to support reliability of the BPS. In general, any standard or requirement the SDT determined to require~~d~~ modification was assigned a high, medium, or low priority. The standards and requirements priorities were established as follows:

- High priority was assigned so that standard or requirement changes would be made quickly enough to avoid an entity having to expend inordinate resources prematurely to comply with a standard or requirement that, after appropriate modification, would not be applicable to that entity;
- Medium priority was assigned if significant effort and resources with no appreciable reliability benefit would be required by an entity to be compliant~~; and~~.
- Low priority was assigned to other changes that may need to be made to further ensure requirements add to reliability, but are not perceived as a significant compliance burden.

The prioritization of each recommendation is identified in Appendix B.

- List of standards (grouped by priority);
- Approval status of the standards (same designations as used in Appendix A);
- Recommendation of changing the Applicability ~~Section~~ section of the standard or by changing the applicability for specific requirements; and
- Recommendation of which applicability options should apply.

4 Technical Discussion

This section provides a review of each group of standards, focusing on the impact of the BES definition on reliability and compliance efforts. This discussion proposes a resolution for each standard, whether it is a change in the Applicability ~~Section~~ section or in a specific requirement, clarification in a guidance document, or no action needed.

4.1 BAL

The group of BAL standards focuses primarily on ensuring the Balancing Authority (BA) has the awareness, ability, and authority to maintain the frequency and operating conditions within its Balancing Authority Area. Only two standards in this group affect GO and/or GOP, and no BAL standard reviewed affected the interaction of a host BA, TOP, or RC with individual BES Elements.

4.1.1 BAL-005 — Automatic Generation Control

The purpose of this standard, as it applies to GOPs, is to ensure that all facilities electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Authority Area so that balancing of resources and demand can be achieved. Ensuring the Facility as a whole is within a Balancing Authority Area ensures the individual units are included. *Therefore, the applicability of the BAL-005 standard does not need to be changed for dispersed power producing resources.*

4.1.2 BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region

The purpose of BAL-001-TRE-1 ~~standard~~ is to maintain Interconnection steady-state frequency within defined limits. This standard should be modified to clarify the applicability for dispersed power producing resources to the total plant level to ensure coordinated performance. However, this is a regional standard and not part of the SDT scope. *The SDT will communicate this recommendation to the relevant Region.*

4.2 COM

The COM standards focus on communication between the RC, BAs, TOPs, and GOPs. The only requirements in any of the current or future enforceable standards that apply to the GOP are clearly intended to apply to the individual GOP registered functional entity (i.e., requires communication between GOPs, TOPs, BAs, and RCs), not the constituent Elements it operates. Consequently, there is no need to differentiate the GOP's obligation for dispersed power producing resources from any other resources. *Therefore, the applicability of the COM-001-2, COM-002-2a, and COM-002-4 standards that were reviewed does not need to be changed for dispersed power producing resources.*

4.3 EOP

The EOP standards focus on emergency operations and reporting. The standards that apply to GO and/or GOP entities are EOP-004 and EOP-005. No EOP standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

4.3.1 EOP-004 — Event Reporting

The purpose of this standard is to improve the reliability of the BES by requiring the reporting of events by ~~Responsible~~ responsible ~~Entities~~entities. The requirements of this standard that apply to the GO and GOP appear to apply to the individual GO and GOP registered functional entity, not the constituent elements. *The SDT has considered whether there is a need to differentiate dispersed power producing resources from any other GO and/or GOP resource and determined that no changes are required to the standard.*

4.3.2 EOP-005 — System Restoration from Blackstart Resources

EOP-005 ensures plans are in place to restore the grid from a de-energized state. The requirements that apply to a GOP are primarily for individual generation facilities designated as Blackstart Resources, with one requirement to participate in restoration exercises or simulations as requested by the RC. The inclusion of Blackstart Resources is already identified in the BES definition through Inclusion I3. The expectation is that all registered GOPs will participate in restoration exercises as requested by ~~its~~ their RC. *Therefore, the applicability of EOP-005 does not need to be changed for dispersed power producing resources.*

4.4 FAC

The FAC standards focus on establishing ratings and limits of the Facility and interconnection requirements to the BES. Several standards apply to GOs and/or GOPs. No FAC standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

4.4.1 FAC-001 — Facility Connection Requirements

Requirements R2 and R3 of this standard apply to any GO that has an external party applying for interconnection to the GO's existing Facility in order to connect to the transmission system. This scenario is uncommon and there is no precedent for applicability of this standard to dispersed power producing resources known to the SDT. Current practice primarily includes the GO stating that they will comply with the standard if this scenario is ever realized. This standard allows the GO to specify the conditions that must be met for the interconnection of the third-party, thus providing inherent flexibility to tailor the requirements specifically for the unique needs of the Facility. *Therefore, the applicability of FAC-001 does not need to be changed for dispersed power producing resources.*

4.4.2 FAC-002 — Coordination of Plans for New Facilities

The purpose of FAC-002 is to ensure coordinated assessments of new facilities. The requirement applicable to GOs requires coordination and cooperation on assessments to demonstrate the impact of new facilities on the interconnected system and to demonstrate compliance with NERC standards and other applicable requirements. The methods used to demonstrate compliance are independent of the type of generation and are typically completed at the point of interconnection. *Therefore, the applicability of FAC-002 does not need to be changed for dispersed power producing resources.*

4.4.3 FAC-003 — Transmission Vegetation Management

The purpose of this standard is to ensure programs and efforts are in place to prevent vegetation-related outages. This standard applies equally to dispersed generation facilities and traditional Facilities in both applicability and current practices, as it pertains to overhead transmission lines of applicable generation

interconnection Facilities. *Therefore, the applicability of FAC-003 does not need to be changed for dispersed power producing resources.*

4.4.4 FAC-008 — Facility Ratings

FAC-008 ensures Facility ratings used in the planning and operation of the BES are established and communicated. The Facility ratings requirement has historically been applicable to dispersed power producing resources and current practices associated with compliance are similar to traditional generation facilities. There is inherent flexibility in the standard requirements for the GO to determine the methodology utilized in determining the Facility ratings.

To identify the Facility rating of a dispersed power producing resource the analysis of the entire suite of Facility components is necessary to adequately identify the minimum and maximum Facility Rating and System Operating Limits, and thus there would be no differentiation between the compliance obligations between dispersed power producing resources and traditional generation. *The SDT believes the industry and Regions would benefit from additional guidance on FAC-008 in the form of ~~changes to add a~~ the technical guidance ~~section to the standard, or other guidance~~provided below.*

Guidelines and Technical Basis

FAC-008 ensures facility ratings used in the planning and operation of the BES are established and communicated. The facility ratings requirement has historically been applicable to dispersed power producing resources and current practices associated with compliance are similar to traditional generation facilities. There is inherent flexibility in the standard requirements for the GO to determine the methodology utilized in determining the facility ratings.

To identify the facility rating of a dispersed power producing resource the analysis of the entire suite of facility components is necessary to adequately identify the minimum and maximum Facility Rating and System Operating Limits, and thus there would be no differentiation between the compliance obligations between dispersed power producing resources and traditional generation.

The use of the term "main step-up transformer" in Requirements R1 and R2 refers to the final GSU (the last transformer(s) used exclusively for stepping up the generator output) prior to the point of interconnection or, when the point of interconnection is before the GSU, the GSU that steps up voltage to transmission line voltage level and is used strictly as a delineation point between Requirements R1 and R2. In an attempt to address this potential misinterpretation, the SDT provides the following clarifications:

1. Referencing the NERC Glossary definition of Facility Ratings~~,~~ identifies that the voltage, current, frequency, and real or reactive power flow through a facility must not violate the equipment rating of any equipment of the facility (that is subjected to the voltage, current, etc.). With this definition, it is clear that each component or piece of equipment must be reviewed to ensure the ratings are not exceeded, and that applicable documentation be maintained.
2. The use of the term "Facilities" in the phrase "…determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer…" could potentially be interpreted to refer only to BES Facilities because the Glossary definition of "Facility" includes the term "Bulk Electric System Element." For dispersed power producing facilities, that could leave out portions of the facility, specifically the collection system. However, the intent of the standard is to address the Facility Ratings of all electrical equipment from the generator to the point of interconnection.

As an example, for solar facilities, a GO or GOP should provide ratings for array or panel, DC Cables (Positive and Negative), combiner boxes, inverters, as well as associated breakers, instrument transformers (CVTs, PTs), disconnect switches, and relays, etc. This is shown in Figure A.

If there are multiple sample units, comprised of a multiple of identical components with identical ratings, then only one sample unit must be provided for that piece of equipment when calculating the facility rating value. For example, if a facility is comprised of 50 identical inverter units rated at 2 MW that have identical combiner box, module string and module compositions/orientations, then the Facility rating would be 50*2 MW = 100 MW.

In order to identify the most limiting component of the facility, a complete analysis of every component in a sample unit must be conducted. Under the assumption that the GO owns the main step-up transformer, this will include analysis from the generator (solar module or WTG) up through the high side terminals of the main step-up transformer. In an effort to simplify this analysis, grouping identical equipment configurations into a sample unit is an accepted industry practice. The following discussion and diagrams provide an explanation of how this could be accomplished for dispersed power producing resources (wind and solar).

Figure A Walk-through: For each sample unit identified, it should be clarified that a thorough rating analysis of each sample unit component must be conducted at least once to identify any potential limiting component and determine the sample unit rating. Upon completion of this analysis and arrival at a rating value, future representations of the sample unit would then be able to utilize this calculated sample unit rating as opposed to reiterating the individual component analysis.

Sample Unit #1: This sample unit is comprised of the 250W solar modules, combiner box "A", conductors and other electrical equipment from the solar module to, but not including, the inverter. This sample unit encompasses three strings. In order to be referenced as a sample unit in future occurrences, this exact configuration must be met (3 strings, same type and number of modules, same conductor type and configuration, and same electrical components).

Sample Unit #2: This sample unit is limited to an individual string and its components (eight 250 W modules and conductors) up to the combiner box "B." The middle string (without dotted line) associated with combiner box B is actually a second instance of the Sample Unit #2 and thus would not need a separate rating analysis and would instead be represented as a multiple of Sample Unit #2 in the overall rating analysis.

Sample Unit #3: This sample unit is also limited to a single string and its components up to combiner box B. While this string utilizes the same type of solar module (250 W) as Sample Unit #2, there are fewer modules in this string, which differentiates this string from Sample Unit #2 and thus requires this string to be represented separately.
Note that combiner box B is not included in either Sample Unit #2 or #3 and thus would need to be rated separately.

Sample Unit #4: This sample unit is limited to an individual string and its components (eight 300 W modules and conductors) up to the combiner box "C." The upper string (without dotted line) associated with combiner box C is actually a third instance of the Sample Unit #2. The lower string (without dotted line) associated with combiner box C is actually a second instance of the sample unit #4. Note that combiner box C is not included in any sample unit and thus would need to be rated separately.

Sample Unit #5: This sample unit is similar to the sample unit #1 configuration but utilizes 300W modules instead of 250W modules thus would need a separate rating analysis.

Sample Unit #6: This sample unit represents all the components and sample units leading up to, and including, the inverter. The lower right-hand section of Figure A shows that the inverter that comprises these various sample units is one of four identical units that feed into a substation bus. Thus, since the rating of this inverter has been identified as 80 kW (from manufacturer) and all the components have previously been thoroughly analyzed, the other three identical units can be represented as other instances of sample unit #6.

Sample Unit #7: This sample unit represents an inverter and/or component configuration that is different from sample unit #6. This scenario, in which the inverter in this sample unit is identical to the inverter utilized in sample unit #6, but the underlying component configuration is different from in sample unit #6 necessitates representation of this sample unit separately from Sample Unit #6.

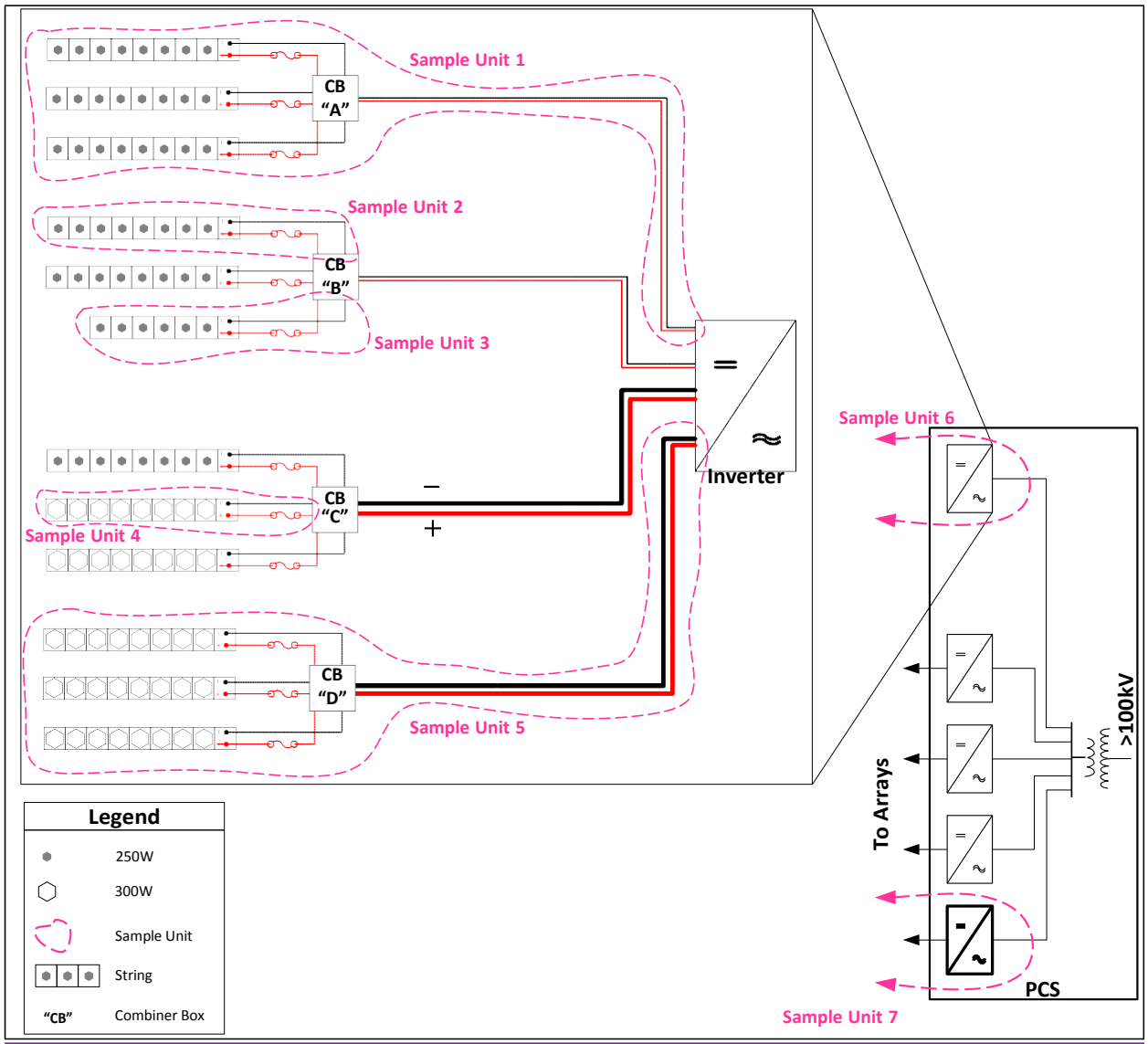

Figure A: Sample Unit Representation (Solar)

Once a complete analysis of the sample unit is conducted, this sample unit can then be referred to in future rating analyses without repeating the complete sample unit analysis. This scenario is illustrated in Table A below.

Table A:

Element	Unit Rating	#Units in system	Rating
Sample Unit #1 (Nine strings of eight 250 W modules each)	18 kW	1	18 kW
Sample Unit #2 (Three strings of eight 250 W modules)	6 kW	3	18 kW
Sample Unit #3 (Three Strings of six 250 W modules)	4.5 kW	1	4.5 kW
Sample Unit #4 (Three strings of six 300 W modules)	5.4 kW	2	10.8 kW
Sample Unit #5 (Nine strings of eight 300 W modules each)	21.6 kW	1	21.6 kW
Sample Unit #6	80 kW	4	320 kW
Sample Unit #7	80 kW	1	80 kW

Figure B Walk-through: For each sample unit identified, it should be clarified that a thorough rating analysis of each sample unit component and all other serial components through to the point of interconnection must be conducted once to identify any potential limiting component and determine the sample unit rating. Upon completion of this analysis and arrival at a rating value, future representations of the sample unit would then be able to utilize this calculated sample unit rating as opposed to reiterating the individual component analysis.

Sample Unit #1: This sample unit is comprised of the Manufacturer "A" wind turbines (WTG) rated at 2.0 MW, the associated step-up transformer, and conductors and other electrical equipment from the WTG to, but not including, the junction box. This sample unit encompasses a string of four WTGs. In order to be referenced as a sample unit in future occurrences, this exact configuration must be met (same type and number of WTGs, same step-up transformer, same conductor type and configuration, and same electrical components).

Sample Unit #2: This sample unit is comprised of the Manufacturer "A" wind turbines (WTG) rated at 2.0 MW, the associated step-up transformer, and conductors and other electrical equipment from the WTG to, but not including, the junction box. This sample unit encompasses a string of six WTGs. The different number of WTGs in this string versus those in the sample unit #1 necessitates a separate consideration from the sample unit #1.

Sample Unit #3: This sample unit is comprised of the Manufacturer "B" wind turbines (WTG) rated at 3.0 MW, the associated step-up transformer, and conductors and other electrical equipment from the WTG to, but not including, the junction box. This sample unit encompasses a string of four WTGs.

Sample Unit #4: This sample unit is comprised of the Manufacturer "B" wind turbines (WTG) rated at 3.0 MW, the associated step-up transformer, and conductors and other electrical equipment from the WTG to, but not including, the junction box. This sample unit encompasses a string of six WTGs. The different number of WTGs in this string versus those in the sample unit #3 necessitates a separate consideration from the sample unit #3.

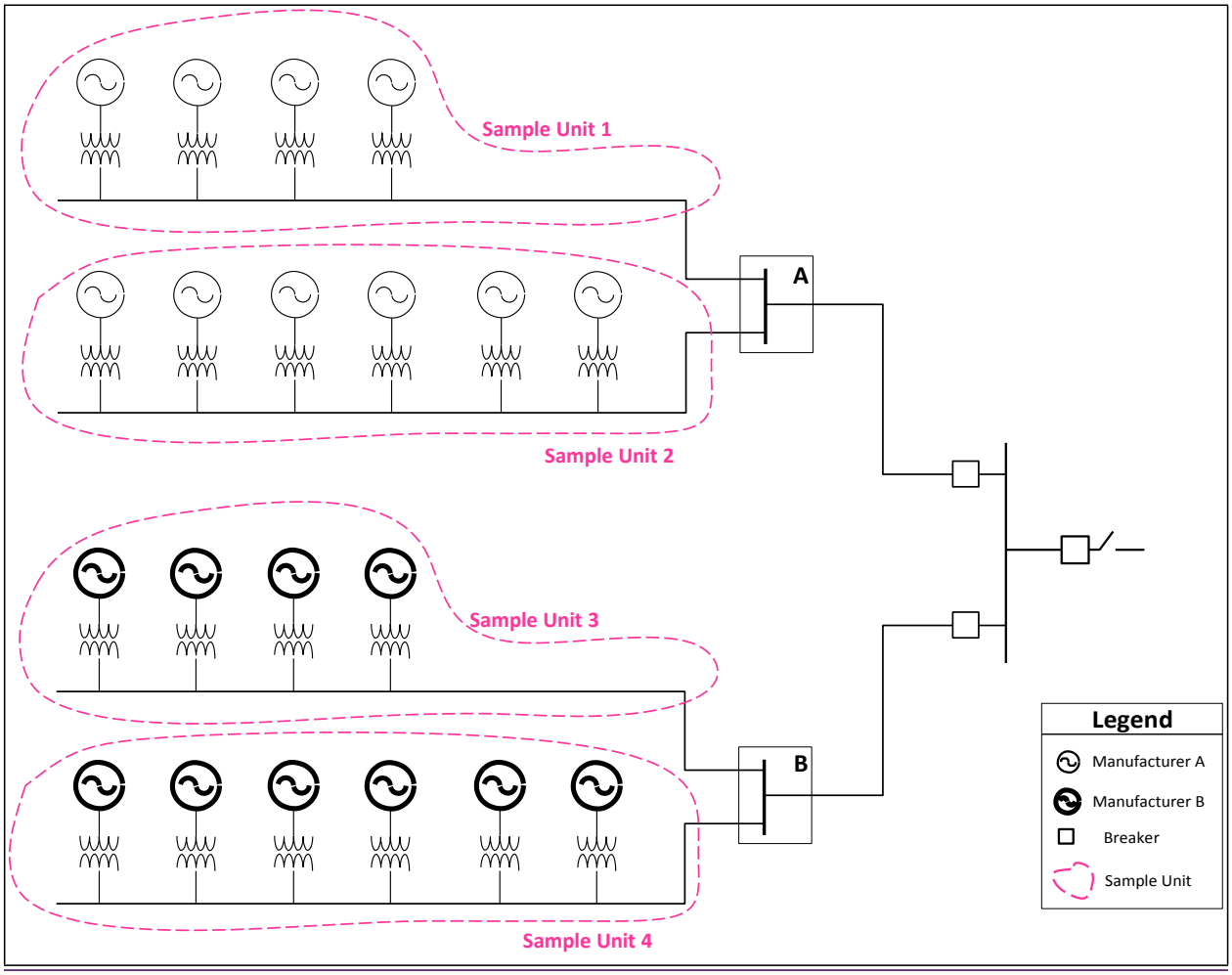

Figure B: Sample Unit Representation (Wind)

4.5 INT

The INT standards provide BAs the authority to monitor power interchange between Balancing Authority Areas. No INT standard is applicable to the GO or GOP, or affects the interaction of a host BA, TOP, or RC with individual BES Elements. *Therefore, the applicability of the INT standards does not need to be changed for dispersed power producing resources.*

4.6 IRO

The IRO standards provide RCs their authority. ~~There are t~~three IRO ~~Standards~~ standards that apply directly to GO and/or GOP entities. ~~There are t~~three standards ~~that~~ apply to the interaction of the RC with individual BES Elements. No other IRO standard reviewed affected the interaction of a host BA, TOP, or RC with GOs and/or GOPs.

4.6.1 IRO-001 — Reliability Coordination — Responsibilities and Authorities[17]

The purpose of these standards and their requirements as applicable to a GOP is to ensure RC directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements, or cannot be physically implemented. If a GOP is unable to follow an RC directive, ~~they are~~it is to inform the RC immediately ~~of such~~.

Directives from RCs have been traditionally applied to the dispersed power producing resource at the aggregate Facility level when they are related to either active power or voltage, such as an output reduction or the provision of voltage support. When such directives are not specific to any one Element within the Facility, it is up to the GOP to determine the appropriate method to achieve the desired result of the directive consistent with other applicable NERC Reliability Standards. When an RC directive specifies a particular Element or Elements at the GOP's Facility, it is the expectation and requirement that the GOP will act as directed, so long as doing so does not violate safety, equipment, or regulatory or statutory requirements or cannot be physically implemented. For example, a directive could specify operation of a particular circuit breaker at a GOP Facility. *For these reasons, the applicability of IRO-001 does not need to be changed for dispersed power producing resources.*

4.6.2 IRO-005 — Reliability Coordination — Current Day Operations[18]

The purpose of this standard and its requirements as ~~it~~ they relate~~s~~ to GOPs is to ensure that when there is a difference in derived limits, the BES is operated to the most limiting parameter. A difference in derived limits can occur on any Element; ~~and~~ therefore, any limitation of the applicability of this standard may create a reliability gap. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of IRO-005 does not need to be changed for dispersed power producing resources.*

[17] Note that IRO-001-3, which is adopted by the Board, was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

[18] Note that applicability to GOPs has been removed in IRO-005-4, which is adopted by the Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

4.6.3 IRO-010 — Reliability Coordinator Data Specification and Collection

The purpose of this standard and its requirement(s) as it relates to GOs and GOPs is to ensure data and information specified by the RC is provided. As each RC area is different in nature, up to and including the tools used to ensure the reliability of the BPS, a ~~'~~one ~~-~~size ~~-~~fits ~~-~~all~~'~~ approach is not appropriate. This Reliability Standard allows ~~for~~ the RC to specify the data and information required from the GO and/or the GOP, based on what is required to support the reliability of the BPS. *Therefore, the applicability of IRO-010 does not need to be changed for dispersed power producing resources.*

4.7 MOD

The MOD ~~group of~~ standards ensure~~s~~ consistent modeling data requirements and reporting procedures. The MOD standards provide a path for Transmission Planners (TPs) and Planning Coordinators (PCs) to reach out to entities for specific modeling information, if required. The SDT believes the existing and proposed modeling standards are sufficient for modeling dispersed power producing resources. However, due to the unique nature of dispersed power producing resources and an effort to bring consistency to the models, *the SDT believes additional guidance on the MOD standards would be beneficial and will communicate its determination to the NERC Planning Committee.*

4.7.1 MOD-010 — Steady-State Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-010 does not need to be changed for dispersed generation resources.*

4.7.2 MOD-012 — Dynamics Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-012 does not need to be changed for dispersed generation resources.*

4.7.3 MOD-024-1 — Verification of Generator Gross and Net Real Power Capability

This standard was established to ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2.[19] *Therefore, the applicability of MOD-024-1 does not need to be changed for dispersed generation resources.*

4.7.4 MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability

This standard was established to ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2. *Therefore, the applicability of MOD-025-1 does not need to be changed for dispersed generation resources.*

[19] MOD-024-1 and MOD-025-1 are Board ~~Adopted~~ adopted but not subject to enforcement. They are commonly followed as good utility practice.

4.7.5 MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. This standard is appropriate for and includes specific provisions for dispersed generation resources to ensure changes in capabilities are reported. *Therefore, the SDT is further evaluating whether to revise the applicability of the standard to align the language with the revised BES definition.*

4.7.6 MOD-026 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions

This standard provides for verification of models and data for voltage control functions. This standard is appropriate for dispersed generation resources. *Originally, the DGR SDT considered clarifying the applicability of the Facilities section; however, upon further review, the DGR SDT recommends no change.*

4.7.7 MOD-027 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

This standard was established to verify that the turbine/governor and frequency control model accurately represents generator unit Real Power response to system frequency variations. This standard is appropriate for dispersed generation resources. *Originally, the DGR SDT considered clarifying the applicability of ~~–~~the Facilities section~~;~~ however, upon further review, the DGR SDT recommends no change.*

4.7.8 MOD-032 — Data for Power System Modeling and Analysis

The MOD-032 standard was established to ensure consistent modeling data requirements and reporting procedures for the planning horizon cases. The nature of dispersed generation resources is a challenge in modeling the steady-state and dynamic electrical properties of the individual components (e.g., individual units, collector system, interconnection components, etc.).

Models for dispersed power producing resources are typically proprietary and unique for each Facility. Generic models exist for dynamic analysis that may provide sufficient accuracy in lieu of a Facility-specific model. Some sections of ~~the~~ MOD-032 Attachment 1 pertain to modeling individual units, which may not be feasible. Guidance should be provided to show how to best model dispersed power producing resources. Such guidance should require modeling requirements for each type of dispersed power producing resource within a Facility and aggregate model for each reasonable aggregation point. *The applicability of MOD-032 does not need to be changed for dispersed power producing resources.*

4.8 NUC

The requirements in standard NUC-001~~—~~, Nuclear Plant Interface Coordination, individually define the applicability to ~~Registered~~ registered ~~Entities~~entities, not to the Elements the entities own or operate. While it is unlikely any Elements that are part of a dispersed power producing resource would be subject to an agreement required by this standard, limiting the applicability of this standard could create a reliability gap, and thus~~,~~ there is no need to differentiate applicability to dispersed generation resources. *Therefore, the applicability of the NUC standard does not need to be changed for dispersed power producing resources.*

4.9 PER

The PER standards focus on operator personnel training. The only requirements in any of the current or future enforceable standards that apply to the GOP is requirement R6 in PER-005-2—, Operations Personnel Training, and it is clearly intended to apply to the individual GOP registered functional entity that controls a fleet of generating facilities, not the constituent Elements it operates. As such, there is no need to differentiate dispersed power producing resources from any other GOP resources. *Therefore, the applicability of the PER standards do not need to be changed for dispersed power producing resources.*

4.10 PRC

The PRC standards establish guidance to ensure appropriate protection is established to protect the BES.

4.10.1 PRC-001-1.1 — System Protection Coordination

Requirement R1 requires GOPs to be familiar with the purpose and limitations of Protection System schemes applied in their area. The recently approved changes to the BES definition extend the applicability of this requirement. Often this familiarity is provided to GOP personnel through training on the basic concepts of relay protection and how it is utilized. The basic relaying concepts utilized in protection on the aggregating equipment at a dispersed generation site typically will not vary significantly from the concepts used in Protection Systems on individual generating units.

Requirement R2 requires that GOPs report protective relay or equipment failures that reduce system reliability. Protective System failures occurring within a single individual generating unit at a dispersed power producing resource will not have any impact on overall system reliability, and thus it should not be necessary for GOPs to report these failures to their TOPs and host BAs. Only failures of Protection Systems on aggregating equipment have the potential to impact BPS reliability and may require notification. When interpreted as stated above, no related changes should be required to the existing PRC-001-1 standard, as the BES definition changes do not have an impact on these requirements.

Requirement R3 requires GOPs to coordinate new protective systems. Coordinating new, and changes to existing, protective relay schemes should be applied to aggregating equipment protection only if a lack of coordination could cause unintended operation or non-operation of an interconnected entity's protection, thus potentially having an adverse impact to the BPS. Existing industry practice is to share/coordinate the protective relay settings on the point of interconnect (e.g., generator leads, radial generator tie-line, etc.) and potentially the main step-up transformer, but not operating (collection) buses, collection feeders, or individual generator protection schemes, as these Protection Systems do not directly coordinate with an interconnected utility's own Protection Systems. Relay protection functions such as under- and ~~overfrequency~~ over frequency and under- and overvoltage changes are independent of the interconnected utility's protective relay settings, and the setting criteria are defined in PRC-024.

Requirement R5 requires GOPs to coordinate changes in generation, transmission, load, or operating conditions that could require changes in the Protection Systems of others. A GOP of a dispersed generation resource should be required to notify its TOP of changes to generation, transmission, load, or operating conditions on an aggregate Facility level.

Project 2007-06 – System Protection Coordination and Project 2014-03 – Revisions to TOP and IRO Standards are presently revising various aspects of this standard or addressing certain requirements in other standards.

For these reasons, the DGR SDT coordinated with the other SDTs currently reviewing this standard and recommended revisions to Requirement R3.1 to indicate that coordination by a GOP with ~~their~~ its TOP and host BA of new, or changes to, protection systems on individual generating units of dispersed power producing resources is not required.

4.10.2 PRC-001-2 — System Protection Coordination

The concerns addressed with PRC-001-1.1b are removed in PRC-001-2, which is adopted by the Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-03 – Revisions to TOP and IRO Standards. This ~~S~~standard version is not in effect and was withdrawn as the proposed versions of the TOP and IRO Reliability Standards included in Project 2014-3 effectively replace PRC-001-2 and other TOP standards. *For this reason, no changes are required.*

4.10.3 PRC-002-NPCC-01— Disturbance Monitoring
PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting

Requirements related to installation of Fault/Disturbance monitoring and/or sequence of events (SOE) recording capabilities on generating units and substation equipment which meet regional specific criteria may require installation of these capabilities on the aggregating equipment at a dispersed power producing resource Facility, and ~~also~~ requires maintenance and periodic reporting requirements to their RRO. However, these requirements have been previously applicable to the aggregating equipment at these dispersed power producing resources, and these capabilities are not required to be installed on the individual generating units. The BES definition changes have no direct impact on applicability of these standards to dispersed power producing resources. *Therefore, the applicability of these standards do*es *not need to be changed for dispersed power producing resources.*[20]

4.10.4 PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations
PRC-004-3 — Protection System Misoperation Identification and Correction

Misoperation reporting per PRC-004 is currently a requirement applied on the aggregating equipment at applicable dispersed power producing resource sites that meet~~ing~~ BPS criteria. The continuation of this analysis and reporting on the aggregating equipment by dispersed generation resource owners can provide value to BPS reliability and should remain in place. However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting, and developing Corrective Action Plans for each individual generating unit that trips at a dispersed power producing resource site, as the tripping of one or a small number of these units has no material impact to ~~the~~ BPS reliability.

Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations. The SDT recognizes that many turbine technologies do not have the design capability of providing sufficient data for an entity

[20] *See* NPCC CGS-005.

to evaluate whether a Misoperation has occurred. Furthermore, dispersed power producing resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g., voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design. This limits the ability to determine whether an individual unit correctly responded to a system disturbance.

However, the SDT maintains that Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a large number of the individual generation resources (aggregate nameplate rating of greater than 75 MVA) incorrectly operated or failed to operate as designed during a system event. As such, if a trip aggregating to greater than 75 MVA occurs in response to a system disturbance, the SDT proposed requiring analysis and reporting of Misoperations of individual generating units for which the root cause of the Protection System operation(s) affected an aggregate rating of greater than 75 MVA of BES Facilities. Note that the SDT selected the 75 MVA nameplate threshold for consistency and to prevent confusion.

The SDT was also concerned with the applicability of events where one or more individual units tripped and the root cause of the operations was identified as a setting error. In this case, the requirements of PRC-004 would be applicable for any individual units where identical settings were applied on the Protection Systems of like individual generation resources identified under Inclusion I4 of the BES definition.

The SDT concluded that it is not necessary under PRC-004 to analyze each individual Protection System Misoperation affecting individual generating units of a dispersed power producing resource. *The SDT recommended changes to the applicability of this standard to require misoperation analysis on individual generating units at a dispersed power producing resource site, only for events affecting greater than 75MVA aggregate nameplate; the SDT determined that this will ensure that common--mode failure scenarios and their potential impact on BPS reliability are appropriately addressed. The SDT's recommended changes passed industry ballot on November 6, 2014, ~~and~~ were approved by the Board on November 13, 2014, and are currently pending regulatory approval.*

4.10.5 PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

Dispersed power producing resource sites typically would not be associated with a WECC Major Transfer Path or Remedial Action Scheme (RAS), and thus would not be affected by PRC-004-WECC-1. If a site were to be involved with one of these paths or schemes, it is likely that associated protection or RAS equipment would be located on the aggregating equipment rather than the individual generating units. As such, the BES definition changes may have an impact on applicability of this standard to dispersed power producing resources. This standard should be modified to clarify the applicability for dispersed generation resources; however, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

4.10.6 PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing

The SDT recognizes that PRC-005-1.1b will be phased out beginning in early 2015. Therefore, the SDT recommends only guidance on PRC-005-1.1b rather than suggesting language changes to the standard. *Therefore, the SDT does not recommend revising the applicability of this standard for dispersed generation resources~~,~~. ~~rather~~Rather, the SDT provided recommendations for revisions to the applicable RSAW to NERC staff, which NERC has implemented after consultation with the Regions.*

4.10.7 PRC-005-2 — Protection System Maintenance
PRC-005-3 — Protection System and Automatic Reclosing Maintenance
PRC-005-4 — Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

~~The~~In some cases, the aggregated capability of the individual generating units may ~~in some cases~~ contribute to the reliability of the BPS; as such, there can be reliability benefit from ensuring that certain BES equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in PRC-005. When evaluated individually, however, the generating units themselves do not have the same impact on BPS reliability as the system used to aggregate the units. The unavailability or failure of any one individual generating unit would have a negligible impact on the aggregated capability of the Facility; this would be irrespective to whether the dispersed generation resource became unavailable due to occurrence of a legitimate fault condition or due to a failure of a control system, protective element, dc supply, etc.

The protection typically utilized in these generating units includes elements ~~which~~that would automatically remove the individual unit from service for certain internal or external conditions, including an internal fault in the unit. These units typically are designed to provide generation output at low voltage levels~~,~~ (i.e., less than 1000 V). Should these protection elements fail to remove the generating unit for this scenario, the impacts would be limited to the loss of the individual generating unit and potentially the next device upstream in the collection system of the dispersed power producing resource. However, this would still only result in the loss of a portion of the aggregated capability of the Facility, which would be equally likely to occur due to a scenario in which a fault occurs on the collection system.

Internal faults on the low~~-~~voltage system of these generating units would not be discernible on the interconnected transmission systems, as this is similar to a fault occurring on a typical utility distribution system fed from a substation designed to serve customer load. It is important to note that the collection system equipment (e.g., breakers, relays, etc.) used to aggregate the individual units may be relied upon to clear the fault condition in both of the above scenarios, which further justifies ensuring portions of the BES collection equipment is maintained appropriately.

For this reason, activities such as Protection System maintenance on each individual generating unit at a dispersed generation Facility would not provide any additional reliability benefits to the BPS, but Protection System maintenance on facilities where generation aggregates to 75 MVA or more would. The SDT proposes that the scope of PRC-005 be limited to include only the protection systems that operate at a point of aggregation above 75 MVA nameplate rating. If the aggregation point occurs at a component in the collection system, then the protection systems associated with this component would be in scope. *The SDT has recommended changes to the Applicability Section (Facilities) of PRC-005-2, -3, and -4 to indicate that maintenance activities should only apply on the aggregating equipment at or above the point where the aggregation exceeds 75 MVA. The Board approved the SDT's recommended applicability changes to PRC-005-2 and PRC-005-3 ~~were approved by the Board~~ on November 13, 2014. The SDT's recommended applicability changes to PRC-005-4 ~~were posted for an initial ballot period that ends on January 22, 2014.~~are pending Board approval.*

4.10.8 PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding PRC-006-SERC -1 — Automatic Underfrequency Load Shedding Requirements

The regional specific PRC-006 standards deviate from the PRC-006-1 standard in that they have specific requirements for GOs. In particular, the NPCC version requires that GOs set their underfrequency tripping to meet certain criteria to ensure reliability of the BPS. Typically, a dispersed generation resource site may have underfrequency protection on both the aggregating equipment (i.e., collection buses or feeders) ~~as well as~~ and the individual generating units. ~~Were~~ If this standard were only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur may still result in a loss of significant generating capacity ~~should~~ if each of the individual generating units trip for the event.

Therefore, it may be appropriate to include the individual generating units at a dispersed generation resource site as subject to this standard. The standard could be interpreted this way as written, but further clarification in the standard language may be considered. While this standard may need to be modified to clarify the applicability for dispersed generation resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

The SERC version of PRC-006 requires GOs to provide, upon request, certain under and overfrequency related set points and other related capabilities of the site relative to system disturbances. It may be appropriate to include the capabilities of the individual generating units at a dispersed generation resource site when providing this information; however, it may be sufficient to provide only the capabilities of a single sample unit within a site, as these units are typically set identically. This would be in addition to any related capabilities or limitations of the aggregating equipment as well. This may be accomplished by providing clarifications in the requirements sections. While this standard may need to be modified to clarify the applicability for dispersed power producing resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

4.10.9 PRC-015 — Special Protection System Data and Documentation
PRC-016 — Special Protection System Misoperations
PRC-017 — Special Protection System Maintenance and Testing

Relatively few dispersed power producing resources own or operate Special Protection Systems (SPSs); however, they do exist and therefore need to be evaluated for applicability based on the revised BES definition. The vast majority of these SPSs involve the aggregating equipment (transformers, collection breakers, etc.) and not the individual generating units. The SPSs are installed to protect the reliability of the BPS, and as such the aggregated response of the site (e.g., reduction in output, complete disconnection from the BES, etc.) is critical, not the response of individual generating units. *Therefore, the applicability of these standards does not need to be changed for dispersed power producing resources.*

4.10.10 PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Dispersed power producing resources typically utilize a site-level voltage control scheme that directs the individual generating units to adjust their output to meet the voltage requirements at an aggregate Facility level. In these cases, the individual generating units will simply no longer respond once they are "maxed out" in providing voltage or reactive changes, but also need to be properly coordinated with protection – trip settings on the aggregating equipment to mitigate the risk of tripping in this scenario. For those facilities that solely regulate voltage at the individual unit, these facilities also need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. The applicability in PRC-019-1 (section 4.2.3) includes a "Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating)." *Therefore, the DGR SDT revised the Facilities section of the standard to clarify that facilities which solely regulate voltage at the individual generating unit are subject to this standard's requirements. The SDT's recommended applicability changes to PRC-019-1 were posted for an initial comment and ballot period scheduled to close December 22, 2014filed with FERC March 13, 2015.*

4.10.11 PRC-023— Transmission Relay Loadability

Dispersed power producing resources in some cases contain facilities and Protection Systems that meet the criteria described in the Applicability Section section (e.g., load-responsive phase Protection System on transmission lines operated at 200 kV or above); however, in the majority of cases these lines are radially connected to the remainder of the BES and are excluded from the standard requirements of PRC-023-3. While certain entities with dispersed power producing resources are required to meet the requirements of PRC-023 on components of their aggregating equipment (e.g., main step-up transformers, interconnecting transmission lines), the standard is not applicable to the individual generating units, as the individual generating units are addressed in PRC-025. The BES definition changes have no direct impact on the applicability of this standard to dispersed power producing resources. *Therefore, the applicability of this standard does not need to be changed for dispersed power producing resources.*

4.10.12 PRC-024— Generator Frequency and Voltage Protective Relay Settings

If the individual generating units at a dispersed power producing resource were excluded from this requirement, it is possible large portions or perhaps the entire output of a dispersed power producing

resource site may be lost during certain system disturbances, negatively impacting BES reliability. The SDT has determined it is appropriate to require that ~~Protection System~~protective relay settings applied on both the individual generating units and aggregating equipment (including any ~~Protection Systems applied on non-BES portions of the aggregating~~non-BES collection system equipment~~),~~) are set ~~within~~ respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. *The SDT therefore recommended changes to the standard requirements to ensure these requirements are applied to the individual power producing resources as well as all equipment, potentially including non-BES equipment, from the individual power producing resource up to the point of interconnection and communicated compliance evidence requirement considerations to NERC staff for RSAW development. The SDT's recommended applicability changes to PRC-024 were ~~posted for an initial comment and ballot period scheduled to close December 22, 2014~~filed with FERC March 13, 2015.*

4.10.13 PRC-025— Generator Relay Loadability

The Protection System utilized on individual generating units at a dispersed power producing Facility may include load-responsive protective relays and thus would be subject to the settings requirements listed in this standard. Were this standard only to apply to aggregating equipment, the net impact to the BPS ~~should~~ if a system disturbance were to occur~~,~~ may be a loss of significant generating capacity ~~should~~ if each of the individual generating units trips for the event. The SDT has determined it is appropriate to require that Protection System settings be applied on both the individual generating units at a dispersed power producing resource site as applicable to this standard. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. As such, the SDT recommends the RSAW be modified as stated above. *The SDT recommended no changes to the standard; however, the DGR SDT communicated compliance evidence requirement considerations to NERC staff for RSAW development.*

4.11 TOP

The TOP standards provide TOPs their authority. ~~There are f~~Four TOP standards ~~that~~ apply directly to GO and GOP entities. The TOP standards as they relate to GOs/GOPs ensure RCs and TOPs can issue directives to the GOP, and the GOP follows such directives. They also ensure GOPs render all available emergency assistance as requested. Finally, they require GO/GOPs to coordinate their operations and outages and provide data and information to the BA and TOP. No TOP standard refers to the interaction of a host BA, TOP, or RC with individual BES Elements.

4.11.1 TOP-001-1a — Reliability Responsibilities and Authorities

This standard as it applies to GOPs is reviewed at the requirement level, with only one change recommended.

4.11.1.1 Requirement R3

The purpose of R~~r~~equirement R3 as it relates to GOPs is to ensure the RC and TOP reliability directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow an RC or TOP reliability directive, they are to inform the RC or TOP immediately ~~of such~~. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed power producing resources from any other GOP resources, and no change to this requirement is needed.*

4.11.1.2 Requirement R6

The purpose of R~~r~~equirement R6 as it relates to GOPs is to ensure all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed power producing resources from any other GOP resources, and no change to this requirement is needed.*

4.11.1.3 Requirement R7

The purpose of R~~r~~equirement R7 as it relates to GOPs is to ensure BES facilities are not removed from service without proper notification and coordination with the TOP and, when time does not permit such prior notification and coordination, notification and coordination shall occur as soon as reasonably possible. This is required to avoid burdens on neighboring systems. It should be noted that the purpose of this standard is to keep the TOP informed of all generating Facility capabilities in case of an emergency. It is assumed that required notification and coordination from the GOP to the TOP would be done in real~~-~~time and through verbal communication media. The concern here is how to apply this to a dispersed power producing resource Facility. The SDT recommends that the GOP report at the aggregate Facility level to the TOP any generator outage above 20 MVA for dispersed power producing resource facilities. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition, which addresses only generating units greater than 20 MVA.
- TOP-002-2.1b Requirement R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the Facility (e.g., 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed power producing resource outages should be reported as "x~~X~~ MW out of y~~Y~~ MW are available." *Therefore, the SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for generator outages greater than 20 MVA.*

4.11.2 TOP-001-3— Transmission Operations[21]

The purpose of this standard as it relates to GOPs is to ensure TOP directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a TOP directive, ~~they are~~it is to inform the TOP immediately ~~of such~~. It directs the TOP to issue directives, and as such, the TOP may provide special requirements for dispersed power producing resources for its unique capabilities. *The SDT ~~recommends~~ recommended that Project 2014-3 provide direction for a dispersed power producing resource to be ~~only~~ reported only at the aggregate facility level. ~~If TOP-001-1a R7 is reintroduced, then the recommendation provided above should be included in their efforts.~~*

4.11.3 TOP-002-2.1b — Normal Operations Planning[22]

This TOP standard has five requirements applied to GOPs. Several modifications are recommended below, and the SDT recommends that the most effective and efficient way to accomplish this is through modification of the Applicability s~~S~~ection of this standard.

4.11.3.1 Requirement R3

The purpose of R~~r~~equirement R3 as it relates to GOPs is to ensure a GOP's current ~~-~~day, next-day and seasonal operations are coordinated with its host BAs and TSP. This requirement relates to planned operations at a generator and does not include unplanned operations such as forced or emergency operations. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources. For example, forecasting available ~~MW~~ megawatts at the aggregated Facility level is currently one method used. The SDT does not see any reliability gap ~~in~~ that would prompt this team to apply R3 to any point less than the dispersed power producing resource aggregated Facility level.

The SDT has not found or been made aware of a reliability gap that would prompt this team to apply R3 to any point less than the dispersed power producing resource aggregated Facility level and recommends such modification to the applicability of this requirement.

4.11.3.2 Requirement R13

The purpose of R~~r~~equirement R13 as it relates to GOPs is to ensure Real Power and Reactive Power capabilities are verified as requested by the BA and TOP. The SDT believes a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT ~~is recommending~~ recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources for the following reasons:

- Due to the nature, amount of individual generators at a dispersed power producing resource, internal Real Power losses, and natural inductance and capacitance of dispersed power resource system connected in series, verification of real and reactive capabilities should be conducted at the dispersed power producing resource aggregate Facility level. Performing verification in this manner will provide an actual net real and reactive capability, which would be seen by both the

[21] Note that TOP-001-2 was adopted by the Board and remanded by FERC. TOP-001-2 is currently under revision as part of Project 2014-03 – Revisions to TOP and IRO Standards, and was posted for additional ballot period that is scheduled to close January 7, 2015 as TOP-001-3.

[22] The GOP applicability is removed in TOP-002-3, which was adopted by the Board. However, TOP-002-3 was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO s~~S~~tandards.

BA and TOP. In addition, performing verification in this manner is also consistent with operating agreements such as an interconnection agreement, which the dispersed power resource has with the TOP and BA.

- MOD-025-2 also provides that verification for any generator ~~<20MVA~~ less than 20MVA may be completed on an individual unit basis or as a "group." Reporting capability at the aggregated Facility level is consistent with the MOD-025-2 provision for group verification.

The SDT recommends a modification to the applicability of this requirement at the aggregated Facility level for dispersed power producing resources.

4.11.3.3 Requirement R14

The purpose of R~~r~~equirement R14 as it relates to GOPs is to ensure BAs and TOPs are notified of changes in real output capabilities without any intentional time delay. It should be noted that the purpose of this requirement is to address unplanned changes in real output capabilities. It is assumed the required notification and coordination from the GOP to the BA and TOP would be done in real ~~-~~time and through verbal communication media. The concern here is how to apply this to dispersed power producing resources. The SDT recommends that the GOP notify at the aggregate Facility level to the TOP any unplanned changes in real output capabilities above 20 MVA. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20 MVA; and
- TOP-002-2.1b R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the Facility (e.g. 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Changes in the real output capabilities of d~~D~~ispersed generation resources ~~changes in real output capabilities~~ should be reported as ~~X~~ "x MW out of y~~Y~~ MW are available." *The SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for unplanned outages greater than 20 MVA.*

4.11.3.4 Requirement R15

The purpose of ~~requirement~~ Requirement R15 as it relates to GOPs is to ensure BAs and TOPs are provided a forecast (e.g., seven days) of expected Real Power. The SDT believes this requirement as requested by the BA or TOP is being applied at the aggregate Facility level for dispersed power producing resources.

Based on the SDT's experience, expected Real Power forecasts (e.g. ~~5~~ five or seven-day~~7~~ forecast) for a dispersed power producing resource traditionally have been~~has been traditionally~~ coordinated with the BA and TOP at the aggregate Facility level for dispersed power producing resources. *Therefore, the SDT recommends that R15 be applied at the aggregate Facility level for dispersed power resources and, as such, modification to the applicability~~applicability~~ of this requirement is necessary.*

4.11.3.5 Requirement R18

The purpose of ~~requirement~~ Requirement R18 as it relates to a GOP is to ensure uniform line identifiers are used when referring to transmission facilities of an interconnected network. The standard applies to

transmission

facilities of an interconnected network, which would not apply to any Elements within the dispersed generation Facility. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

4.11.4 TOP-003-1— Planned Outage Coordination

This TOP Standard has three requirements applied to GOPs. Modification to one of these requirements is recommended.

4.11.4.1 Requirement R1

The purpose of ~~requirement~~ Requirement R1 as it relates to GOPs is to ensure TOPs are provided planned outage information on a daily basis for any scheduled generator outage greater than~~>~~ 50 MW for the next day. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

4.11.4.2 Requirement R2

The purpose of ~~requirement~~ Requirement R2 as it relates to GOPs is to ensure all scheduled outages of voltage~~-~~ regulating equipment ~~scheduled outages~~ are planned and coordinated with affected BAs and TOPs. A modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources.

Based on the SDT's experience, scheduled outages of voltage~~-~~ regulating equipment at a dispersed power producing resource traditionally has been ~~traditionally~~ provided to the BA and TOP at the aggregate Facility level for dispersed power producing resources. Outages of voltage~~-~~ regulating equipment at a dispersed power producing resource are coordinated typically as a reduction in Reactive Power capabilities, specifying whether it is inductive, capacitive, or both. Additionally, automatic voltage regulators that do not necessarily provide Reactive Power, but direct the actions of equipment that do supply Reactive Power, are typically coordinated at the aggregate Facility level as they usually are the master controller for all voltage~~-~~ regulating equipment at the Facility. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, ~~which~~ that would prompt this team to apply R2 to any point less than the dispersed power producing resource aggregated Facility level and, as such, determined a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

4.11.4.3 Requirement R3

The purpose of ~~requirement~~ Requirement R3 as it relates to GOPs is to ensure scheduled outages of telemetering and control equipment and associated communication channels are planned and coordinated among BAs and TOPs. Based on the SDT's technical expertise, scheduled outages of telemetering and control equipment and associated communication channels at a dispersed power producing resource traditionally have been ~~traditionally~~ provided to the BA and TOP at the aggregate Facility level ~~for dispersed power producing resources~~. In addition, only scheduled outages of telemetering and control equipment and associated communication channels that can affect the BA and TOP are coordinated with the BA and TOP. *Therefore, the applicability of this requirement does not need to be changed for dispersed power producing resources.*

4.11.5 TOP-006 — Monitoring System Conditions

The purpose of this standard as it relates to GOPs is to ensure BAs and TOPs know the status of all generation resources available for use as informed by the GOP. It should also be noted that the purpose of this standard is to ensure that critical reliability parameters are monitored in real -time. It then can be extrapolated that the requirement, "GOP shall inform…," is done by sending dispersed power producing resource telemetry in real -time and through a digital communication medium, such as an ICCP link or RTU. The SDT ~~feels~~ concludes that a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate Facility level for dispersed power producing resources for the following reasons:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20 MVA. If removing less than ~~<~~20 MVA would cause a burden to the BPS, then the threshold for inclusion in the BES would have been less than 20 MVA.~~;~~
- Routine maintenance is frequently completed on a small portion of the entire Facility (e.g. 2% of the generators are out of service on any given day) such as to not have a significant impact to the output capability of the Facility. Additionally, it is not uncommon to have individual generating units at a dispersed power producing resource to go into a failure mode due to internal factors of the equipment, such as hydraulic fluid pressure tolerances, gearbox -bearing thermal tolerances, etc. As such, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS~~; and~~.
- As this standard requires real-time monitoring, this is most likely completed through a digital medium such as an ICCP link or RTU. The data that a dispersed power resource provides to the BA and TOP in real -time should include the aggregate active power output of the Facility, among other telemetry points. These data specifications are usually outlined in interconnection agreements among the parties.

Based on the SDT's technical expertise, BAs and TOPs are informed by the GOP of all generation resources available at the dispersed power producing resource at the aggregate Facility level. Traditionally the dispersed power producing resources ~~are~~ provid~~e~~ing the BA and TOP, at minimum, the following telemetry points in real -time: aggregate Real Power, aggregate Reactive Power and main high-side circuit breaker status. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap, ~~which~~ that would prompt this team to apply these requirement to any point less than where the dispersed power producing resource aggregates and, as ~~in~~ such, recommends a modification to the applicability of this requirement ~~is necessary~~ for dispersed power producing resources.*

4.12 TPL

At the time of this paper, these standards do not affect GOs or GOPs directly. Input from GO or GOP entities is provided to transmission planning entities through the MOD standards. *Therefore, the applicability of the TPL standards does not need to be changed for dispersed power producing resources.*

4.13 VAR

The VAR standards exist to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained. T~~here are t~~wo VAR S~~s~~tandards ~~that~~ apply to GOs and/or GOPs.

The voltage and/or reactive schedule provided by TOPs is specified to be at the point of interconnection or the point specified in the interconnection agreement.

4.13.1 VAR-001 — Voltage and Reactive Control (WECC Regional Variance)

The purpose of this standard as it relates to GOPs in WECC is to ensure a generator voltage schedule is issued that is appropriate for the type of generator(s) at a specific Facility. Additionally, it requires GOPs to have a methodology for how the voltage schedule is met, taking into account the type of equipment used to maintain the voltage schedule. Based on the SDT's technical expertise, voltage control and voltage schedule adherence for dispersed power producing resources occurs at the aggregate Facility level. There is no need to differentiate dispersed generation resources from any other GOP resources. *Therefore, the applicability of VAR-001 does not need to be changed for dispersed generation resources.*

4.13.2 VAR-002-2b — Generator Operation for Maintaining Network Voltage Schedules
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

The purpose of these standards as they relate to GOs and GOPs is to ensure generators operate in automatic voltage control mode as required by the TOP voltage or reactive power schedule provided to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the SDT's technical expertise, voltage control and voltage schedule adherence for dispersed power producing resources occurs at the aggregate Facility level, and such guidance should be provided.

In addition, the voltage-controlling equipment and the methodology to ensure the Facility has an automatic and dynamic response to ensure the TOP's instructions are maintained can be very different for each Facility. It is implied in VAR-001-3 that each TOP should understand capabilities of the generation Facility and the requirements of the transmission system to ensure that a mutually agreeable solution/schedule is used.

4.13.3 VAR-002-2b — Requirement R3.1
VAR-002-3 — Requirement R4

4.13.4 The purpose of these requirements is to ensure that a GOP notifies the TOP, within 30 minutes, of any status and capability changes of any generator Reactive Power resource, including automatic voltage regulator, power system stabilizer, or alternative voltage controlling device. Based on the experience of the SDT, status and capability changes ~~is~~ are traditionally coordinated at the aggregate Facility level point of interconnection. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R3.1 and VAR-002-3 R4 for dispersed power producing resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.* ~~**VAR-002-2b — Requirement R4**~~
~~**VAR-002-3 — Requirement R5**~~

4.13.4 VAR-002-2b — Requirement R4
VAR-002-3 — Requirement R5

The purpose of these requirements is to ensure that Transmission Operators and Transmission Planners have appropriate information and provide guidance to the GOP in regard~~s~~ to Generator Operator's ~~s~~ transformers to ensure voltage levels, reactive flows, and reactive resources are maintained within

applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the experience of the SDT, dispersed power producing resources' individual generator transformers traditionally have ~~traditionally~~ been excluded from the requirements of VAR-002-2b R4 and VAR-002-3 R5, as they are not used to improve voltage performance on the Interconnection. As such, applicability should be limited to transformers with at least one winding at a voltage of 100 kV or above. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R4 and VAR-002-3 R5 for dispersed generation resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*

4.14 CIP

4.14.1 CIP ~~v~~Version 5

The CIP standards are still under revision in Project 2014-02. The DGR SDT and the CIP SDT continue to coordinate revisions to the CIP standards, and will update this section to reflect the outcome of that effort at the appropriate time.

The CIP standards ensure physical and cyber security for BES Cyber Assets and BES Cyber Systems critical to the reliability and security of the BES. CIP-002 identifies critical assets or systems of a Facility, while CIP-003 to CIP-011 depend on the outcome of the CIP-002 assessment to determine applicability.

During the first comment period for the Project 2014-02 CIP Version 5 Revisions, the SDT ~~first comment period, it~~ received comments to modify CIP-003-6 in the Applicability ~~Section~~section. The CIP SDT made ~~drastic~~ significant modifications to the second posting of CIP-003-6 to take into account~~s~~ all of the comments received., ~~which~~ Thiswas posted for an additional 45-day comment and ballot period on September 3, 2014.

At its September meeting, the DGR SDT had a focused discussion with the CIP SDT surrounding the technical nature of the dispersed power producing resources and how it relates to the CIP standards. The coordinating effort resulted in discussions of the revised CIP-003-6. As for that posted revised standard, the CIP SDT took the approach of including an Attachment 1 for Responsible Entities. ~~The~~ Attachment 1 requires elements to be developed in Responsible Entities' cyber-security plan~~(s)~~ for assets containing low- impact BES ~~Cyber~~ cyber ~~Systems~~systems. The elements in CIP-003-6, Attachment 1 allow flexibility for the controls ~~–~~to be established for each of the main four elements below. The CIP SDT encourages observers of the DGR SDT to review ~~the~~ Attachment 1 in detail. ~~Here~~ Below is some information regarding the attachment.

Element 1: Security Awareness

The intent of the security awareness program is for entities to reinforce good cyber-security practices with their personnel at least once every 15 calendar months. ~~It is up to t~~The entity ~~as to~~decides the topics and how it schedules the~~mse topics~~. The Responsible Entity should be able to produce the awareness material that was delivered and the delivery method(s) (posters, emails, topics at staff meetings, etc.) that were used. The SDT does not intend that the Responsible Entity must maintain lists of recipients and track the reception of the awareness material by personnel.

Element 2: Physical Security

The Responsible Entity has flexibility in the controls used to restrict physical access to low- impact BES Cyber Systems at a BES asset using one or a combination of access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may utilize perimeter controls (e.g., fences with locked gates, guards, site access policies, etc.) and/or more granular areas of physical access control in areas where low- impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of authorized users are not required.

Element 3: Electronic Access Controls

Where Low Impact External Routable Connectivity (LERC) or Dial-up Connectivity exists, the Responsible Entity must document and implement controls that include the LERC and Dial-up Connectivity to the BES asset such that the low- impact BES Cyber Systems located at the BES asset are protected. Two glossary terms are included in order to help clarify and simplify the language in Attachment 1. The SDT's intent in creating these terms is to avoid confusion with the similar concepts and requirements (ESP, EAP, ERC, EACMS) needed for high- and medium- impact BES Cyber Systems by ~~utilizing~~ using separate terms that apply only to assets containing low- impact BES Cyber Systems.

Element 4: Cyber Security Incident Response

The entity should have one or more documented cyber security incident response plan~~s~~ that includes each of the topics listed. For assets that do not have LERC, it is not the intent to increase their risk by increasing the level of connectivity in order to have real-time monitoring. The intent is, if in the normal course of business suspicious activities are noted at an asset containing low- impact BES Cyber Systems, ~~there is~~ a cyber security incident response plan ~~that~~ will guide the entity through responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Therefore, the DGR SDT recommends that no changes be made to the proposed CIP-003-6. CIP-002-5.1 needs to remain as is, because entities must go through the process for identifying and categorizing ~~its~~ their BES Cyber Systems and ~~their~~ associated BES Cyber Assets. The controls put in place for proposed CIP- 003-6, Attachment 1, are not burdensome, are realistic and achievable, and do~~es~~ not express undue compliance burden. In conclusion, the DGR SDT states that the reliability objective of these controls is~~are~~ adequate and the applicability of CIP-003-6 should not be modified.

The SDT states that the CIP Version 5 Revisions SDT should consider developing guidance documentation around the following areas:

- Low ~~I~~impact BES Cyber Systems that must comply with a limited number of requirements, all located in CIP-003-5. The only technical requirement is R2, which will be modified during the current drafting activity to add clarity to the requirement. The SDT notes that the CIP Version 5 Revisions SDT should consider developing guidance around how this requirement relates to dispersed generation;
- Any programmable logic device that has the capability to shut down the plant within 15 minutes~~; and~~
- Remote access from third- party entities into the SCADA systems that control the aggregate capacity of a Facility should be assessed to determine if there is a need of any additional cyber security policies.

The SDT intends to recommend guidance for those companies that only operate their turbines from one central location. Individual Elements lumped into a BES Cyber System should be addressed. When operations are on a turbine-by-turbine basis, the SDT believes there should not be rigid controls in place. The inability to "swim upstream" should be addressed as well. Further, the guidance intends to address when manufacturers operate or have control of the SCADA environment to conduct troubleshooting and other tasks, and ensure that proper security is in place.

NERC staff has committed to facilitate communication between the SDT and the CIP Version 5 Revisions SDT as appropriate to ensure alignment and to develop language for guidance, coordinated between the two SDTs. *Therefore, the applicability of CIP standards does not need to be changed for dispersed generation resources.*

Appendix A: List of Standards

Appendix B: List of Standards Recommended for Further Review

Draft White Paper

Proposed Revisions to the Applicability of NERC Reliability Standards to Dispersed Generation Resources

Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Drafting Team

June 12, 2015

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1 Executive Summary

The purpose of this White Paper is to provide background and technical rationale for proposed revisions to the applicability of several North American Electric Reliability Corporation (NERC) Reliability Standards, and in some cases the standard requirements. The goal of the NERC Project 2014-01 Standards Applicability for Dispersed Generation Resources[1] standard drafting team (SDT) is to ensure that the Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System (BPS), as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Authority (FERC) in 2014,[2] the intent of this effort is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The SDT reviewed all standards that apply to GOs and GOPs[3] and determined how each standard requirement should be appropriately applied to dispersed power producing resources, categorized as follows:

- The existing standard language was appropriate when applied to dispersed power producing resources and does not need to be addressed;
- The existing standard language was appropriate when applied to dispersed power producing resources, but additional NERC guidance documentation is needed to clarify how to implement the requirements for dispersed power producing resources; and
- The existing standard language needs to be modified in order to account for the unique characteristics of dispersed power producing resources. This could be accomplished through the applicability section of the standard in most cases or, if required, through narrowly tailored changes to the individual requirements.

From this review, the SDT determined that three (3) Reliability Standards required immediate attention to clarify the applicability of the Reliability Standards to dispersed power producing resources for the benefit of industry stakeholders. These standards (relevant versions) are:

- PRC-004;[4]
- PRC-005;[5] and
- VAR-002.

The SDT recognized that many other standards[6] required further review to determine the necessity and the type of clarification or guidance for the applicability to dispersed power producing resources. This

[1] Although the BES definition uses the term "dispersed power producing resources," the SAR and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.
[2] Glossary of Terms Used in NERC Reliability Standards, updated March 12, 2014.
[3] See Appendix A.
[4] Reliability Standard PRC-004 was revised as part of Project 2010-05.1 Protection Systems: Misoperations.
[5] Reliability Standard PRC-005 was revised as part of Project 2007-17.3 Protection System Maintenance and Testing – Phase 3.
[6] See Appendix B.

necessity is based on how each standard requirement, as written, would apply to dispersedpower producing resources and the individual generating units at these facilities, considering the now currently effective BES definition. The proposed resolutions target the applicability of the standard or target specific individual requirements. There are additional methods to ensure consistent applicability throughout the Regions, including having guidance issued by NERC through Reliability Standard Audit Worksheet (RSAW) language revisions. These tools, among others, have been considered and employed by the SDT throughout the drafting effort.

This White Paper includes: (1) a description of the history of standards applicability to dispersed power producing resources; (2) identification of circumstances and practices that are unique to dispersed power producing resources; and (3) a determination of the priority to address standards, supported by corresponding technical justification.

The SDT's intent is to modify this document over the course of this project to document the SDT's rationale and technical justification for each standard until the work of the SDT is complete. The SDT considers the sections of the White Paper that address the high-priority standards to be in final draft form. The SDT may provide further revisions to the remainder of the White Paper.

2 Purpose

The purpose of this White Paper is to provide background and technical rationale for proposed revisions to the applicability of several Reliability Standards[7] or requirements that apply to GOs and/or GOPs. The goal of the proposed applicability changes is to provide the GOs and GOPs of dispersed generation resources with clarity regarding their responsibility for requirements that impact the reliability of the BPS, as the characteristics of operating dispersed generation can be unique. The SDT seeks to provide clarity through the method most appropriate for each standard, such as by: (1) revising applicability language in the standard; (2) revising language in the requirements to address changes to applicability; (3) recommending changes to the RSAW associated with the standard; or (4) recommending a reliability guideline or reference document.

This document describes the design, operational characteristics, and unique features of dispersed power producing resources. The recommendations identified in this document consider the purpose and time horizon of the standards and requirements, as well as the avoidance of applying requirements in a manner that has no significant effect on reliability.[8] This document provides justification of, and proposes revisions to, the applicability of the Reliability Standards and requirements, both existing and in development, and should be considered guidance for future standard development efforts. However, please note that the recommendations provided in this paper are subject to further review and revision.

Note that while this White Paper may provide examples of dispersed power producing resources, the concepts presented are not specific to any one technology. The SDT in general has referenced the *BES Definition Reference Document*[9], which also refers to "dispersed power producing resources." Although the BES definition uses the term "dispersed power producing resources," the Standard Authorization Request (SAR) and the SDT also use the term "dispersed generation resources." For the purposes of this paper, these terms are interchangeable.

[7] Note that "Reliability Standard" is defined in the NERC Glossary as "approved by FERC," but that the SDT reviewed approved standards, as well as revisions to standards proposed in other projects.
[8] *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 at P 81 (2012).
[9] *Bulk Electric System Definition Reference Document*, Version 2, April 2014. http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_reference_document_20140325_final_clean.pdf.

3 Background

Industry stakeholders submitted a SAR to the NERC Standards Committee, requesting that the applicability of Reliability Standards or the requirements of Reliability Standards be revised to ensure that the Reliability Standards are not imposing requirements on dispersed generation resource components that are unnecessary or counterproductive to the reliability of the BPS. The SDT's focus has been to ensure that Reliability Standards are applied to dispersed power producing resources to support an effective defense-in-depth strategy and an adequate level of reliability for the interconnected BPS.

For purposes of this effort, dispersed power producing resources are those individual resources that aggregate to a total capacity greater than 75 MVA gross nameplate rating, and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This request is related to the approved definition of the BES from Project 2010-17,[10] which resulted in the inclusion of distinct components of dispersed generation resources.

3.1 BES Definition

The BES definition[11] includes the following inclusion criterion addressing dispersed generation resources:

> *I4. Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:*
>
> *a) the individual resources; and*
> *b) the system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.*

The *BES Definition Reference Document*[12] includes a description of what constitutes a dispersed generation resource:

> *Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to: solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.*

[10] http://www.nerc.com/pa/Stand/Pages/Project2010-17_BES.aspx
[11] *Glossary of Terms Used in NERC Reliability Standards*, updated March 12, 2014. http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[12] *Bulk Electric System Definition Reference Document*, Version 2, April 2014. http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_reference_document_20140325_final_clean.pdf.

3.2 Dispersed Power Producing Resources

Dispersed power producing resources are often considered to be variable energy resources such as wind and solar. This description is not explicitly stated in the BES definition; however, NERC and FERC characterize variable generation in this manner regarding the purpose of Inclusion I4 of the definition.[13] Therefore, the SDT is considering the reliability impacts of variable generation that depends on a primary fuel source that varies over time and cannot be stored.[14] Reliably integrating high levels of variable resources—wind, solar, ocean, and some forms of hydro—into the BPS require significant changes to traditional methods used for system planning and operation.[15] While these resources provide challenges to system operation, they are instrumental in meeting government-established renewable portfolio standards and requirements that are based on vital public interests.[16]

3.2.1 Design Characteristics

For dispersed power producing resources to be economically viable, it is necessary for the equipment to be geographically dispersed. The generating capacity of individual generating modules can be as small as a few hundred watts to as large as several megawatts. Factors leading to this dispersion requirement include:

- Practical maximum size for wind generators to be transported and installed at a height above ground to optimally utilize the available wind resource;
- Spacing of wind generators geographically to avoid interference between units;
- Solar panel conversion efficiency and solar resource concentration to obtain usable output; and
- Cost-effective transformation and transmission of electricity.

The utilization of small generating units results in a large number of units (e.g., several hundred wind generators or several million solar panels) installed collectively as a single facility that is connected to the Transmission system.

Dispersed power producing resources interconnected to the transmission system typically have a control system at the group level that controls voltage and power output of the Facility. The control system is capable of recognizing the capability of each individual unit or inverter to appropriately distribute the contribution required of the Facility across the available units or inverters. The variable generation control system must also recognize and account for the variation of uncontrollable factors such as wind speed and solar irradiance levels. Thus, for some standards discussed in this paper, it is appropriate to apply requirements at the plant level rather than the individual generating unit.

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[13] NERC December 13, 2013 filing, page 15 (FERC Docket No. RD14-2); NERC December 13, 2013 filing, page 17 (FERC Docket No. RD14-2); NERC January 25, 2012 filing, page 18 (FERC Docket No. RD14-2), FERC Order Approving Revised Definition, Docket No. RD14-2-000, Issued March 20, 2014.

[14] *Electricity Markets and Variable Generation Integration*, WECC, January 6, 2011.

[15] *Accommodating High Levels of Variable Generation*, NERC, April, 2009. http://www.nerc.com/files/ivgtf_report_041609.pdf

[16] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 335, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

3.2.2 Operational Characteristics

Dispersed power producing resources often rely on a variable energy source (wind, for example) that is not able to be stored. Because of this, a Facility operator cannot provide a precise forecast of the expected output to a Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC); however, short-term forecasting capability is improving and thus reducing uncertainty.[17] The forecasting and variable operating conditions are well understood by BAs, TOPs, and RCs as evidenced by the successful operation of these generating resources over the years. Dispersed generation resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g., voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities' design.

Many older dispersed power producing resources are limited in their ability to provide essential reliability services. However, due to technological improvements, newer dispersed generation resources are capable of providing system support for voltage and frequency. For efficiency, the facilities are designed to provide the system requirements at the point of interconnection to the transmission system.

3.2.3 Reliability Impact

A dispersed power producing resource is typically made up of many individual generating units. In most cases, the individual generating units are similar in design and from one manufacturer. The aggregated capability of the Facility may in some cases contribute significantly to the reliability of the BPS. As such, there can be reliability benefits from ensuring the equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in certain applicable NERC standards. When evaluated individually, however, the individual generating units often do not provide a significant impact to BPS reliability, as the unavailability or failure of any one individual generating resource may have a negligible impact on the aggregated capability of the Facility. The SDT acknowledges that FERC addressed the question of whether individual resources should be included in the BES definition in Order Nos. 773 and 773-A and concluded that individual wind turbine generators should be included as part of the BES. The SDT is not challenging this conclusion, but rather is addressing the applicability of standards on a requirement-by-requirement basis as necessary to account for the unique characteristics of dispersed generation. Thus, the applicability of requirements to individual generating units may be unnecessary except in cases where a common-mode issue exists that could lead to a loss of a significant number of units or the entire Facility in response to a transmission system event.

3.3 Drafting Team Efforts

The SDT approached this project in multiple phases. First, after a thorough discussion of the new definition of the BES, the SDT reviewed each standard, as shown in Appendix A, at a high level to recommend changes that would promote consistent applicability for dispersed power producing resources through the entire set of Reliability Standards. This review provided the type of changes proposed, the justification for the changes, and the priority of the changes. The SDT documented its review in this White Paper, which will continue to be updated throughout the SDT efforts. The second phase, currently

[17] "*Electricity Markets and Variable Generation Integration,*" WECC, January 6, 2011. https://www.wecc.biz/committees/StandingCommittees/JGC/VGS/MWG/ActivityM1/WECC%20Whitepaper%20-%20Electricity%20Markets%20and%20Variable%20Generation%20Integration.pdf

in progress, includes revising standards where necessary and supporting the balloting and commenting process.

3.3.1 Scope of Standards Reviewed

Initially, the focus of the standards review was on standards and requirements applicable to GOs and GOPs. However, during discussions, a question was raised to the SDT regarding whether consideration is necessary for other requirements that affect the interaction of a Balancing Authority (BA), Transmission Operator (TOP), or Reliability Coordinator (RC) with individual BES Elements. For example, a requirement that states, "an RC shall monitor BES Elements" may unintentionally affect the RC operator due to the revised BES definition. As such, the SDT took a high-level look at all standards adopted by the NERC Board of Trustees (Board) or approved by FERC to ensure this issue was not significant.

All standards that were reviewed are listed in Appendix A along with the status of the standards as of December 11, 2014. The fields in Appendix A include the following:

- List of standards (grouped by approval status)
- Approval status of the standards (status types listed below):
  - Subject to Enforcement
  - Subject to Future Enforcement
  - Filed and Pending Regulatory Approval
  - Pending Regulatory Filing
  - Designated for Retirement (two standards—MOD-024-1 and MOD-025-1—officially listed as Filed and Pending Regulatory Approval but will be superseded by MOD-025-2)
  - In Concurrent Active Development
- Indication of change or additional review necessary

The SDT also reviewed, at a high level, any approved regional standards. In cases where a change is recommended to a regional standard, the SDT will notify the affected Region. In addition, the SDT is prepared to provide recommendations to other active NERC standard development efforts, where appropriate.

Status	Number of Standards	Number of Standards to be Addressed (Standard, RSAW, Guidance or Further Review)
NERC Standards	**166**	**27**
Subject to Enforcement	101	12
Subject to Future Enforcement	20	5
Pending Regulatory Approval	28	4
Pending Regulatory Filing	7	0
Designated for Retirement	2	0
Proposed for Remand	8	6
Region-specific Standards (*Out of Scope)	**17**	**4**
Subject to Enforcement	15	3
Subject to Future Enforcement	2	1
Pending Regulatory Approval	0	0
Grand Total	**183**	**31**

3.3.2 Reliability Objectives

The SDT used the following reliability objectives to review the standards:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC standards;
- The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand;
- Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably;
- Plans for Emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented;
- Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems;
- Personnel responsible for planning and operating interconnected bulk power systems shall be trained and qualified and have the responsibility and authority to implement actions;
- The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis; and
- Bulk power systems shall be protected from malicious physical or cyber attacks.

3.3.3 Prioritization Methodology

The SDT established a prioritization to review and modify applicability changes recommended to NERC standards and requirements. The SDT evaluated each requirement to identify the appropriate applicability to support reliability of the BPS. In general, any standard or requirement the SDT determined to require modification was assigned a high, medium, or low priority. The standards and requirements priorities were established as follows:

- High priority was assigned so that standard or requirement changes would be made quickly enough to avoid an entity having to expend inordinate resources prematurely to comply with a standard or requirement that, after appropriate modification, would not be applicable to that entity.
- Medium priority was assigned if significant effort and resources with no appreciable reliability benefit would be required by an entity to be compliant.
- Low priority was assigned to other changes that may need to be made to further ensure requirements add to reliability, but are not perceived as a significant compliance burden.

The prioritization of each recommendation is identified in Appendix B.

- List of standards (grouped by priority);
- Approval status of the standards (same designations as used in Appendix A);
- Recommendation of changing the Applicability section of the standard or by changing the applicability for specific requirements; and
- Recommendation of which applicability options should apply.

4 Technical Discussion

This section provides a review of each group of standards, focusing on the impact of the BES definition on reliability and compliance efforts. This discussion proposes a resolution for each standard, whether it is a change in the Applicability section or in a specific requirement, clarification in a guidance document, or no action needed.

4.1 BAL

The group of BAL standards focuses primarily on ensuring the Balancing Authority (BA) has the awareness, ability, and authority to maintain the frequency and operating conditions within its Balancing Authority Area. Only two standards in this group affect GO and/or GOP, and no BAL standard reviewed affected the interaction of a host BA, TOP, or RC with individual BES Elements.

4.1.1 BAL-005 — Automatic Generation Control

The purpose of this standard, as it applies to GOPs, is to ensure that all facilities electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Authority Area so that balancing of resources and demand can be achieved. Ensuring the Facility as a whole is within a Balancing Authority Area ensures the individual units are included. *Therefore, the applicability of the BAL-005 standard does not need to be changed for dispersed power producing resources.*

4.1.2 BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region

The purpose of BAL-001-TRE-1 is to maintain Interconnection steady-state frequency within defined limits. This standard should be modified to clarify the applicability for dispersed power producing resources to the total plant level to ensure coordinated performance. However, this is a regional standard and not part of the SDT scope. *The SDT will communicate this recommendation to the relevant Region.*

4.2 COM

The COM standards focus on communication between the RC, BAs, TOPs, and GOPs. The only requirements in any of the current or future enforceable standards that apply to the GOP are clearly intended to apply to the individual GOP registered functional entity (i.e., requires communication between GOPs, TOPs, BAs, and RCs), not the constituent Elements it operates. Consequently, there is no need to differentiate the GOP's obligation for dispersed power producing resources from any other resources. *Therefore, the applicability of the COM-001-2, COM-002-2a, and COM-002-4 standards that were reviewed does not need to be changed for dispersed power producing resources.*

4.3 EOP

The EOP standards focus on emergency operations and reporting. The standards that apply to GO and/or GOP entities are EOP-004 and EOP-005. No EOP standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

4.3.1 EOP-004 — Event Reporting

The purpose of this standard is to improve the reliability of the BES by requiring the reporting of events by responsible entities. The requirements of this standard that apply to the GO and GOP appear to apply

to the individual GO and GOP registered functional entity, not the constituent elements. *The SDT has considered whether there is a need to differentiate dispersed power producing resources from any other GO and/or GOP resource and determined that no changes are required to the standard.*

4.3.2 EOP-005 — System Restoration from Blackstart Resources

EOP-005 ensures plans are in place to restore the grid from a de-energized state. The requirements that apply to a GOP are primarily for individual generation facilities designated as Blackstart Resources, with one requirement to participate in restoration exercises or simulations as requested by the RC. The inclusion of Blackstart Resources is already identified in the BES definition through Inclusion I3. The expectation is that all registered GOPs will participate in restoration exercises as requested by their RC. *Therefore, the applicability of EOP-005 does not need to be changed for dispersed power producing resources.*

4.4 FAC

The FAC standards focus on establishing ratings and limits of the Facility and interconnection requirements to the BES. Several standards apply to GOs and/or GOPs. No FAC standard reviewed affects the interaction of a host BA, TOP, or RC with individual BES Elements.

4.4.1 FAC-001 — Facility Connection Requirements

Requirements R2 and R3 of this standard apply to any GO that has an external party applying for interconnection to the GO's existing Facility in order to connect to the transmission system. This scenario is uncommon and there is no precedent for applicability of this standard to dispersed power producing resources known to the SDT. Current practice primarily includes the GO stating that they will comply with the standard if this scenario is ever realized. This standard allows the GO to specify the conditions that must be met for the interconnection of the third party, thus providing inherent flexibility to tailor the requirements specifically for the unique needs of the Facility. *Therefore, the applicability of FAC-001 does not need to be changed for dispersed power producing resources.*

4.4.2 FAC-002 — Coordination of Plans for New Facilities

The purpose of FAC-002 is to ensure coordinated assessments of new facilities. The requirement applicable to GOs requires coordination and cooperation on assessments to demonstrate the impact of new facilities on the interconnected system and to demonstrate compliance with NERC standards and other applicable requirements. The methods used to demonstrate compliance are independent of the type of generation and are typically completed at the point of interconnection. *Therefore, the applicability of FAC-002 does not need to be changed for dispersed power producing resources.*

4.4.3 FAC-003 — Transmission Vegetation Management

The purpose of this standard is to ensure programs and efforts are in place to prevent vegetation-related outages. This standard applies equally to dispersed generation facilities and traditional Facilities in both applicability and current practices, as it pertains to overhead transmission lines of applicable generation interconnection Facilities. *Therefore, the applicability of FAC-003 does not need to be changed for dispersed power producing resources.*

4.4.4 FAC-008 — Facility Ratings

FAC-008 ensures Facility ratings used in the planning and operation of the BES are established and communicated. The Facility ratings requirement has historically been applicable to dispersed power producing resources, and current practices associated with compliance are similar to traditional generation facilities. There is inherent flexibility in the standard requirements for the GO to determine the methodology utilized in determining the Facility ratings.

To identify the Facility rating of a dispersed power producing resource, the analysis of the entire suite of Facility components is necessary to adequately identify the minimum and maximum Facility Rating and System Operating Limits, and thus there would be no differentiation between the compliance obligations between dispersed power producing resources and traditional generation. *The SDT believes the industry and Regions would benefit from additional guidance on FAC-008 in the form of the technical guidance provided below.*

Guidelines and Technical Basis

FAC-008 ensures facility ratings used in the planning and operation of the BES are established and communicated. The facility ratings requirement has historically been applicable to dispersed power producing resources, and current practices associated with compliance are similar to traditional generation facilities. There is inherent flexibility in the standard requirements for the GO to determine the methodology utilized in determining the facility ratings.

To identify the facility rating of a dispersed power producing resource, the analysis of the entire suite of facility components is necessary to adequately identify the minimum and maximum Facility Rating and System Operating Limits, and thus there would be no differentiation between the compliance obligations between dispersed power producing resources and traditional generation.

The use of the term “main step-up transformer” in Requirements R1 and R2 refers to the final GSU (the last transformer(s) used exclusively for stepping up the generator output) prior to the point of interconnection or, when the point of interconnection is before the GSU, the GSU that steps up voltage to transmission line voltage level and is used strictly as a delineation point between Requirements R1 and R2. In an attempt to address this potential misinterpretation, the SDT provides the following clarifications:

1. Referencing the NERC Glossary definition of Facility Ratings identifies that the voltage, current, frequency, and real or reactive power flow through a facility must not violate the equipment rating of any equipment of the facility (that is subjected to the voltage, current, etc.). With this definition, it is clear that each component or piece of equipment must be reviewed to ensure the ratings are not exceeded, and that applicable documentation be maintained.
2. The use of the term “Facilities” in the phrase “…determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step-up transformer…” could potentially be interpreted to refer only to BES Facilities because the Glossary definition of “Facility” includes the term “Bulk Electric System Element.” For dispersed power producing facilities, that could leave out portions of the facility, specifically the collection system. However, the intent of the standard is to address the Facility Ratings of all electrical equipment from the generator to the point of interconnection.

As an example, for solar facilities, a GO or GOP should provide ratings for array or panel, dc cables (positive and negative), combiner boxes, and inverters, as well as associated breakers, instrument transformers (CVTs, PTs), disconnect switches, and relays, etc. This is shown in Figure A.

If there are multiple sample units comprised of a multiple of identical components with identical ratings, then only one sample unit must be provided for that piece of equipment when calculating the facility rating value. For example, if a facility is comprised of 50 identical inverter units rated at 2 MW that have identical combiner box, module string, and module compositions/orientations, then the Facility rating would be 50*2 MW = 100 MW.

In order to identify the most limiting component of the facility, a complete analysis of every component in a sample unit must be conducted. Under the assumption that the GO owns the main step-up transformer, this will include analysis from the generator (solar module or WTG) up through the high side terminals of the main step-up transformer. In an effort to simplify this analysis, grouping identical equipment configurations into a sample unit is an accepted industry practice. The following discussion and diagrams provide an explanation of how this could be accomplished for dispersed power producing resources (wind and solar).

Figure A Walk-through: For each sample unit identified, it should be clarified that a thorough rating analysis of each sample unit component must be conducted at least once to identify any potential limiting component and determine the sample unit rating. Upon completion of this analysis and arrival at a rating value, future representations of the sample unit would then be able to utilize this calculated sample unit rating as opposed to reiterating the individual component analysis.

Sample Unit #1: This sample unit is comprised of the 250 W solar modules, combiner box "A," conductors, and other electrical equipment from the solar module to, but not including, the inverter. This sample unit encompasses three strings. In order to be referenced as a sample unit in future occurrences, this exact configuration must be met (three strings, same type and number of modules, same conductor type and configuration, and same electrical components).

Sample Unit #2: This sample unit is limited to an individual string and its components (eight 250 W modules and conductors) up to the combiner box "B." The middle string (without dotted line) associated with combiner box B is actually a second instance of the Sample Unit #2 and thus would not need a separate rating analysis and would instead be represented as a multiple of Sample Unit #2 in the overall rating analysis.

Sample Unit #3: This sample unit is also limited to a single string and its components up to combiner box B. While this string utilizes the same type of solar module (250 W) as Sample Unit #2, there are fewer modules in this string, which differentiates this string from Sample Unit #2 and thus requires this string to be represented separately.
Note that combiner box B is not included in either Sample Unit #2 or #3 and thus would need to be rated separately.

Sample Unit #4: This sample unit is limited to an individual string and its components (eight 300 W modules and conductors) up to the combiner box "C." The upper string (without dotted line) associated with combiner box C is actually a third instance of the Sample Unit #2. The lower string (without dotted line) associated with combiner box C is actually a second instance of the sample unit #4. Note that combiner box C is not included in any sample unit and thus would need to be rated separately.

Sample Unit #5: This sample unit is similar to the sample unit #1 configuration but utilizes 300W modules instead of 250W modules thus would need a separate rating analysis.

Sample Unit #6: This sample unit represents all the components and sample units leading up to, and including, the inverter. The lower right-hand section of Figure A shows that the inverter that comprises

these various sample units is one of four identical units that feed into a substation bus. Thus, since the rating of this inverter has been identified as 80 kW (from manufacturer) and all the components have previously been thoroughly analyzed, the other three identical units can be represented as other instances of sample unit #6.

Sample Unit #7: This sample unit represents an inverter and/or component configuration that is different from sample unit #6. This scenario, in which the inverter in this sample unit is identical to the inverter utilized in sample unit #6, but the underlying component configuration is different from in Sample Unit #6, necessitates representation of this sample unit separately from Sample Unit #6.

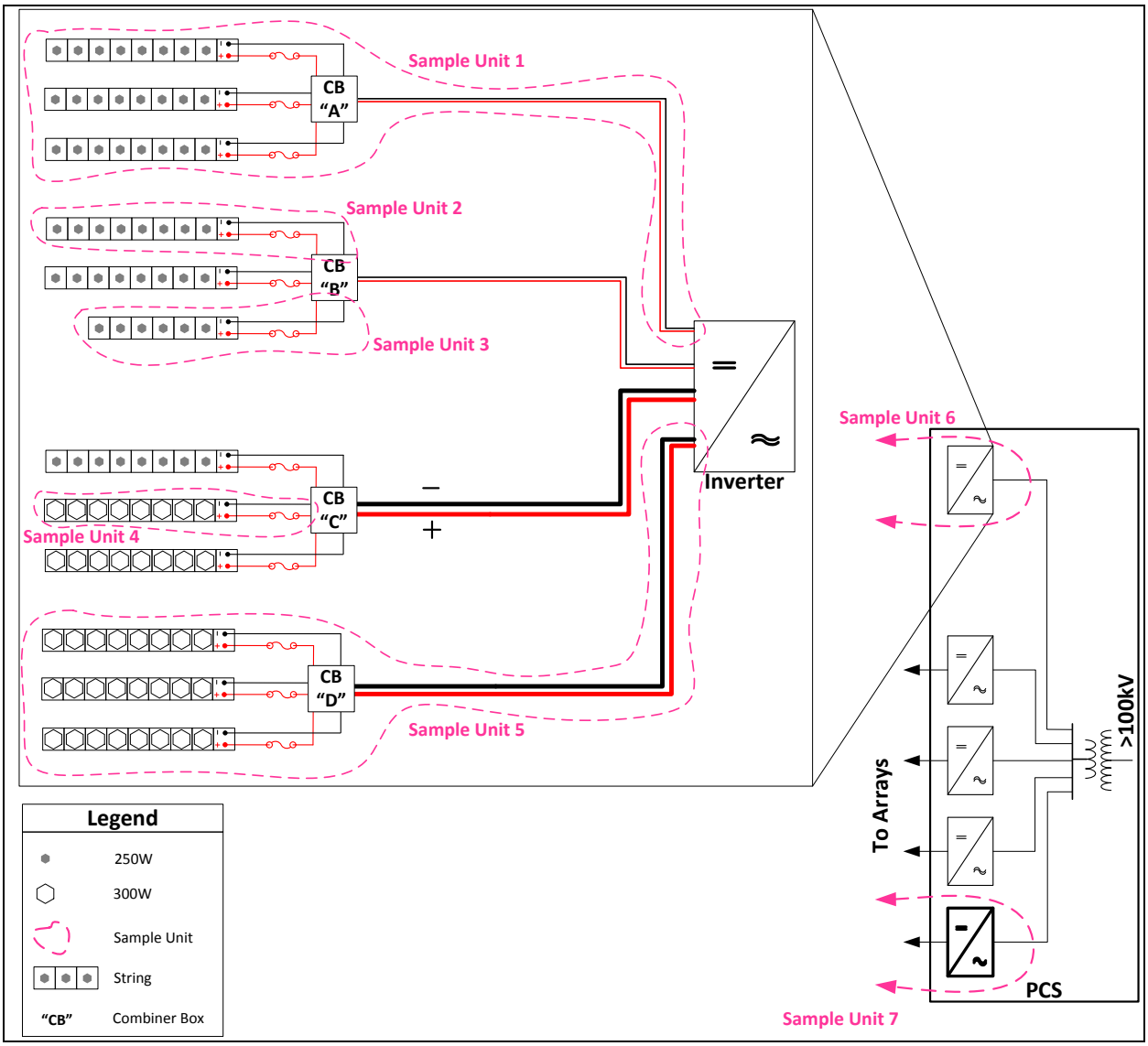

Figure A: Sample Unit Representation (Solar)

Once a complete analysis of the sample unit is conducted, this sample unit can then be referred to in future rating analyses without repeating the complete sample unit analysis. This scenario is illustrated in Table A below.

Table A:

Element	Unit Rating	#Units in system	Rating
Sample Unit #1 (Nine strings of eight 250 W modules each)	18 kW	1	18 kW
Sample Unit #2 (Three strings of eight 250 W modules)	6 kW	3	18 kW
Sample Unit #3 (Three strings of six 250 W modules)	4.5 kW	1	4.5 kW
Sample Unit #4 (Three strings of six 300 W modules)	5.4 kW	2	10.8 kW
Sample Unit #5 (Nine strings of eight 300 W modules each)	21.6 kW	1	21.6 kW
Sample Unit #6	80 kW	4	320 kW
Sample Unit #7	80 kW	1	80 kW

Figure B Walk-through: For each sample unit identified, it should be clarified that a thorough rating analysis of each sample unit component and all other serial components through to the point of interconnection must be conducted once to identify any potential limiting component and determine the sample unit rating. Upon completion of this analysis and arrival at a rating value, future representations of the sample unit would then be able to utilize this calculated sample unit rating as opposed to reiterating the individual component analysis.

Sample Unit #1: This sample unit is comprised of the Manufacturer "A" wind turbines (WTG) rated at 2.0 MW, the associated step-up transformer, and conductors and other electrical equipment from the WTG to, but not including, the junction box. This sample unit encompasses a string of four WTGs. In order to be referenced as a sample unit in future occurrences, this exact configuration must be met (same type and number of WTGs, same step-up transformer, same conductor type and configuration, and same electrical components).

Sample Unit #2: This sample unit is comprised of the Manufacturer "A" wind turbines (WTG) rated at 2.0 MW, the associated step-up transformer, and conductors and other electrical equipment from the WTG to, but not including, the junction box. This sample unit encompasses a string of six WTGs. The different number of WTGs in this string versus those in the sample unit #1 necessitates a separate consideration from the sample unit #1.

Sample Unit #3: This sample unit is comprised of the Manufacturer "B" wind turbines (WTG) rated at 3.0 MW, the associated step-up transformer, and conductors and other electrical equipment from the WTG to, but not including, the junction box. This sample unit encompasses a string of four WTGs.

Sample Unit #4: This sample unit is comprised of the Manufacturer "B" wind turbines (WTG) rated at 3.0 MW, the associated step-up transformer, and conductors and other electrical equipment from the WTG to, but not including, the junction box. This sample unit encompasses a string of six WTGs. The different number of WTGs in this string versus in the sample unit #3 necessitates a separate consideration from the sample unit #3.

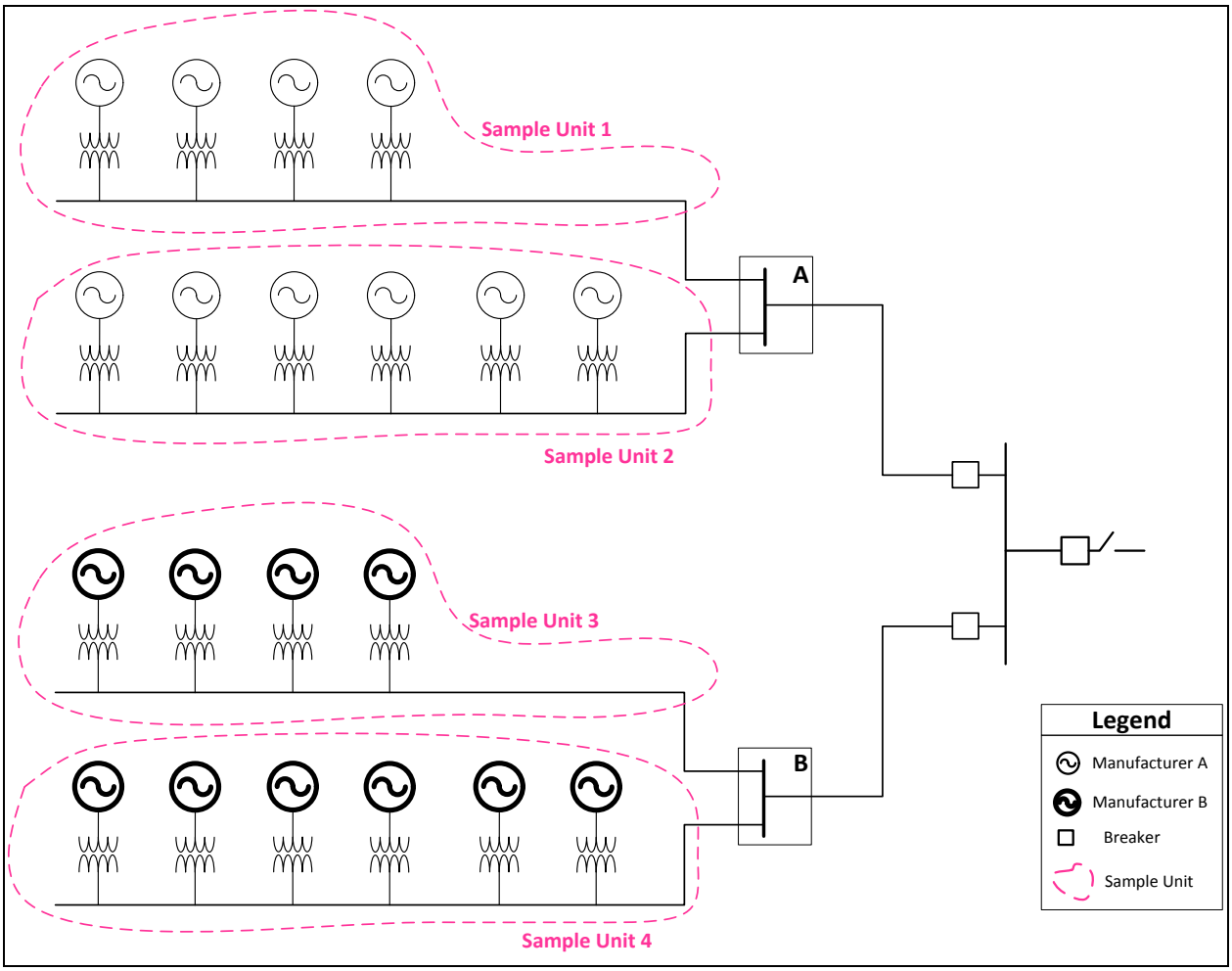

Figure B: Sample Unit Representation (Wind)

4.5 INT

The INT standards provide BAs the authority to monitor power interchange between Balancing Authority Areas. No INT standard is applicable to the GO or GOP, or affects the interaction of a host BA, TOP, or RC with individual BES Elements. *Therefore, the applicability of the INT standards does not need to be changed for dispersed power producing resources.*

4.6 IRO

The IRO standards provide RCs their authority. Three IRO standards apply directly to GO and/or GOP entities. Three standards apply to the interaction of the RC with individual BES Elements. No other IRO standard reviewed affected the interaction of a host BA, TOP, or RC with GOs and/or GOPs.

4.6.1 IRO-001 — Reliability Coordination — Responsibilities and Authorities[18]

The purpose of these standards and their requirements as applicable to a GOP is to ensure RC directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements, or cannot be physically implemented. If a GOP is unable to follow an RC directive, it is to inform the RC immediately.

Directives from RCs have been traditionally applied to the dispersed power producing resource at the aggregate Facility level when they are related to either active power or voltage, such as an output reduction or the provision of voltage support. When such directives are not specific to any one Element within the Facility, it is up to the GOP to determine the appropriate method to achieve the desired result of the directive consistent with other applicable NERC Reliability Standards. When an RC directive specifies a particular Element or Elements at the GOP's Facility, it is the expectation and requirement that the GOP will act as directed, so long as doing so does not violate safety, equipment, or regulatory or statutory requirements or cannot be physically implemented. For example, a directive could specify operation of a particular circuit breaker at a GOP Facility. *For these reasons, the applicability of IRO-001 does not need to be changed for dispersed power producing resources.*

4.6.2 IRO-005 — Reliability Coordination — Current Day Operations[19]

The purpose of this standard and its requirements as they relate to GOPs is to ensure that when there is a difference in derived limits, the BES is operated to the most limiting parameter. A difference in derived limits can occur on any Element; therefore, any limitation of the applicability of this standard may create a reliability gap. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of IRO-005 does not need to be changed for dispersed power producing resources.*

[18] Note that IRO-001-3, which is adopted by the Board, was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.
[19] Note that applicability to GOPs has been removed in IRO-005-4, which is adopted by the Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO Standards.

4.6.3 IRO-010 — Reliability Coordinator Data Specification and Collection

The purpose of this standard and its requirement(s) as it relates to GOs and GOPs is to ensure data and information specified by the RC is provided. As each RC area is different in nature, up to and including the tools used to ensure the reliability of the BPS, a one-size-fits-all approach is not appropriate. This Reliability Standard allows the RC to specify the data and information required from the GO and/or the GOP, based on what is required to support the reliability of the BPS. *Therefore, the applicability of IRO-010 does not need to be changed for dispersed power producing resources.*

4.7 MOD

The MOD standards ensure consistent modeling data requirements and reporting procedures. The MOD standards provide a path for Transmission Planners (TPs) and Planning Coordinators (PCs) to reach out to entities for specific modeling information, if required. The SDT believes the existing and proposed modeling standards are sufficient for modeling dispersed power producing resources. However, due to the unique nature of dispersed power producing resources and an effort to bring consistency to the models, *the SDT believes additional guidance on the MOD standards would be beneficial and will communicate its determination to the NERC Planning Committee.*

4.7.1 MOD-010 — Steady-State Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-010 does not need to be changed for dispersed generation resources.*

4.7.2 MOD-012 — Dynamics Data for Transmission System Modeling and Simulation

This standard is anticipated to be retired in the near future. There is no need to differentiate dispersed generation resources from any other GOP resources as discussed in 5.7.8 regarding MOD-032. *Therefore, the applicability of MOD-012 does not need to be changed for dispersed generation resources.*

4.7.3 MOD-024-1 — Verification of Generator Gross and Net Real Power Capability

This standard was established to ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2.[20] *Therefore, the applicability of MOD-024-1 does not need to be changed for dispersed generation resources.*

4.7.4 MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability

This standard was established to ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess BES reliability. This standard will be superseded by MOD-025-2. *Therefore, the applicability of MOD-025-1 does not need to be changed for dispersed generation resources.*

[20] MOD-024-1 and MOD-025-1 are Board-adopted but not subject to enforcement. They are commonly followed as good utility practice.

4.7.5 MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. This standard is appropriate for and includes specific provisions for dispersed generation resources to ensure changes in capabilities are reported. *Therefore, the SDT is further evaluating whether to revise the applicability of the standard to align the language with the revised BES definition.*

4.7.6 MOD-026 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions

This standard provides for verification of models and data for voltage control functions. This standard is appropriate for dispersed generation resources. *Originally, the DGR SDT considered clarifying the applicability of the Facilities section; however, upon further review, the DGR SDT recommends no change.*

4.7.7 MOD-027 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

This standard was established to verify that the turbine/governor and frequency control model accurately represents generator unit Real Power response to system frequency variations. This standard is appropriate for dispersed generation resources. *Originally, the DGR SDT considered clarifying the applicability of the Facilities section; however, upon further review, the DGR SDT recommends no change.*

4.7.8 MOD-032 — Data for Power System Modeling and Analysis

The MOD-032 standard was established to ensure consistent modeling data requirements and reporting procedures for the planning horizon cases. The nature of dispersed generation resources is a challenge in modeling the steady-state and dynamic electrical properties of the individual components (e.g., individual units, collector system, interconnection components, etc.).

Models for dispersed power producing resources are typically proprietary and unique for each Facility. Generic models exist for dynamic analysis that may provide sufficient accuracy in lieu of a Facility-specific model. Some sections of MOD-032 Attachment 1 pertain to modeling individual units, which may not be feasible. Guidance should be provided to show how to best model dispersed power producing resources. Such guidance should require modeling requirements for each type of dispersed power producing resource within a Facility and aggregate model for each reasonable aggregation point. *The applicability of MOD-032 does not need to be changed for dispersed power producing resources.*

4.8 NUC

The requirements in standard NUC-001, Nuclear Plant Interface Coordination, individually define the applicability to registered entities, not to the Elements the entities own or operate. While it is unlikely any Elements that are part of a dispersed power producing resource would be subject to an agreement required by this standard, limiting the applicability of this standard could create a reliability gap, and thus there is

no need to differentiate applicability to dispersed generation resources. *Therefore, the applicability of the NUC standard does not need to be changed for dispersed power producing resources.*

4.9 PER

The PER standards focus on operator personnel training. The only requirements in any of the current or future enforceable standards that apply to the GOP is requirement R6 in PER-005-2, Operations Personnel Training, and it is clearly intended to apply to the individual GOP registered functional entity that controls a fleet of generating facilities, not the constituent Elements it operates. As such, there is no need to differentiate dispersed power producing resources from any other GOP resources. *Therefore, the applicability of the PER standards does not need to be changed for dispersed power producing resources.*

4.10 PRC

The PRC standards establish guidance to ensure appropriate protection is established to protect the BES.

4.10.1 PRC-001-1.1 — System Protection Coordination

Requirement R1 requires GOPs to be familiar with the purpose and limitations of Protection System schemes applied in their area. The recently approved changes to the BES definition extend the applicability of this requirement. Often this familiarity is provided to GOP personnel through training on the basic concepts of relay protection and how it is utilized. The basic relaying concepts utilized in protection on the aggregating equipment at a dispersed generation site typically will not vary significantly from the concepts used in Protection Systems on individual generating units.

Requirement R2 requires that GOPs report protective relay or equipment failures that reduce system reliability. Protective System failures occurring within a single individual generating unit at a dispersed power producing resource will not have any impact on overall system reliability, and thus it should not be necessary for GOPs to report these failures to their TOPs and host BAs. Only failures of Protection Systems on aggregating equipment have the potential to impact BPS reliability and may require notification. When interpreted as stated above, no related changes should be required to the existing PRC-001-1 standard, as the BES definition changes do not have an impact on these requirements.

Requirement R3 requires GOPs to coordinate new protective systems. Coordinating new, and changes to existing, protective relay schemes should be applied to aggregating equipment protection only if a lack of coordination could cause unintended operation or non-operation of an interconnected entity's protection, thus potentially having an adverse impact to the BPS. Existing industry practice is to share/coordinate the protective relay settings on the point of interconnect (e.g., generator leads, radial generator tie-line, etc.) and potentially the main step-up transformer, but not operating (collection) buses, collection feeders, or individual generator protection schemes, as these Protection Systems do not directly coordinate with an interconnected utility's own Protection Systems. Relay protection functions such as under- and over frequency and under- and overvoltage changes are independent of the interconnected utility's protective relay settings, and the setting criteria are defined in PRC-024.

Requirement R5 requires GOPs to coordinate changes in generation, transmission, load, or operating conditions that could require changes in the Protection Systems of others. A GOP of a dispersed

generation resource should be required to notify its TOP of changes to generation, transmission, load, or operating conditions on an aggregate Facility level.

Project 2007-06 – System Protection Coordination and Project 2014-03 – Revisions to TOP and IRO Standards are presently revising various aspects of this standard or addressing certain requirements in other standards.

For these reasons, the DGR SDT coordinated with the other SDTs currently reviewing this standard and recommended revisions to Requirement R3.1 to indicate that coordination by a GOP with its TOP and host BA of new, or changes to, protection systems on individual generating units of dispersed power producing resources is not required.

4.10.2 PRC-001-2 — System Protection Coordination

The concerns addressed with PRC-001-1.1b are removed in PRC-001-2, which is adopted by the Board. However, this standard was included in the proposed remand by FERC and is subject to revision as part of Project 2014-03 – Revisions to TOP and IRO Standards. This standard version is not in effect and was withdrawn as the proposed versions of the TOP and IRO Reliability Standards included in Project 2014-3 effectively replace PRC-001-2 and other TOP standards. *For this reason, no changes are required.*

4.10.3 PRC-002-NPCC-01 — Disturbance Monitoring
PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting

Requirements related to installation of Fault/Disturbance monitoring and/or sequence of events (SOE) recording capabilities on generating units and substation equipment which meet regional specific criteria may require installation of these capabilities on the aggregating equipment at a dispersed power producing resource Facility, and requires maintenance and periodic reporting requirements to their RRO. However, these requirements have been previously applicable to the aggregating equipment at these dispersed power producing resources, and these capabilities are not required to be installed on the individual generating units. The BES definition changes have no direct impact on applicability of these standards to dispersed power producing resources. *Therefore, the applicability of these standards does not need to be changed for dispersed power producing resources.*[21]

4.10.4 PRC-004-2.1a — Analysis and Mitigation of Transmission and Generation Protection System Misoperations
PRC-004-3 — Protection System Misoperation Identification and Correction

Misoperation reporting per PRC-004 is currently a requirement applied on the aggregating equipment at applicable dispersed power producing resource sites that meet BPS criteria. The continuation of this analysis and reporting on the aggregating equipment by dispersed generation resource owners can provide value to BPS reliability and should remain in place. However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting, and developing Corrective Action Plans for each individual generating unit that trips at a dispersed power producing resource site, as the tripping of one or a small number of these units has no material impact to BPS reliability.

[21] *See* NPCC CGS-005.

Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations. The SDT recognizes that many turbine technologies do not have the design capability of providing sufficient data for an entity to evaluate whether a Misoperation has occurred. Furthermore, dispersed power producing resources by their nature result in each individual generating unit potentially experiencing varied power system parameters (e.g., voltage, frequency, etc.) due to varied impedances and other variations in the aggregating facilities design. This limits the ability to determine whether an individual unit correctly responded to a system disturbance.

However, the SDT maintains that Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a large number of the individual generation resources (aggregate nameplate rating of greater than 75 MVA) incorrectly operated or failed to operate as designed during a system event. As such, if a trip aggregating to greater than 75 MVA occurs in response to a system disturbance, the SDT proposed requiring analysis and reporting of Misoperations of individual generating units for which the root cause of the Protection System operation(s) affected an aggregate rating of greater than 75 MVA of BES Facilities. Note that the SDT selected the 75 MVA nameplate threshold for consistency and to prevent confusion.

The SDT was also concerned with the applicability of events where one or more individual units tripped and the root cause of the operations was identified as a setting error. In this case, the requirements of PRC-004 would be applicable for any individual units where identical settings were applied on the Protection Systems of like individual generation resources identified under Inclusion I4 of the BES definition.

The SDT concluded that it is not necessary under PRC-004 to analyze each individual Protection System Misoperation affecting individual generating units of a dispersed power producing resource. *The SDT recommended changes to the applicability of this standard to require misoperation analysis on individual generating units at a dispersed power producing resource site, only for events affecting greater than 75 MVA aggregate nameplate; the SDT determined that this will ensure that common-mode failure scenarios and their potential impact on BPS reliability are appropriately addressed. The SDT's recommended changes passed industry ballot on November 6, 2014, were approved by the Board on November 13, 2014, and are currently pending regulatory approval.*

4.10.5 PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

Dispersed power producing resource sites typically would not be associated with a WECC Major Transfer Path or Remedial Action Scheme (RAS), and thus would not be affected by PRC-004-WECC-1. If a site were to be involved with one of these paths or schemes, it is likely that associated protection or RAS equipment would be located on the aggregating equipment rather than the individual generating units. As such, the BES definition changes may have an impact on applicability of this standard to dispersed power producing resources. This standard should be modified to clarify the applicability for dispersed generation resources; however, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

4.10.6 PRC-005-1.1b — Transmission and Generation Protection System Maintenance and Testing

The SDT recognizes that PRC-005-1.1b will be phased out beginning in early 2015. Therefore, the SDT recommends only guidance on PRC-005-1.1b rather than suggesting language changes to the standard. *Therefore, the SDT does not recommend revising the applicability of this standard for dispersed generation resources. Rather, the SDT provided recommendations for revisions to the applicable RSAW to NERC staff, which NERC has implemented after consultation with the Regions.*

4.10.7 PRC-005-2 — Protection System Maintenance
PRC-005-3 — Protection System and Automatic Reclosing Maintenance
PRC-005-4 — Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

In some cases, the aggregated capability of the individual generating units may contribute to the reliability of the BPS; as such, there can be reliability benefit from ensuring that certain BES equipment utilized to aggregate the individual units to a common point of connection are operated and maintained as required in PRC-005. When evaluated individually, however, the generating units themselves do not have the same impact on BPS reliability as the system used to aggregate the units. The unavailability or failure of any one individual generating unit would have a negligible impact on the aggregated capability of the Facility; this would be irrespective to whether the dispersed generation resource became unavailable due to occurrence of a legitimate fault condition or due to a failure of a control system, protective element, dc supply, etc.

The protection typically utilized in these generating units includes elements that would automatically remove the individual unit from service for certain internal or external conditions, including an internal fault in the unit. These units typically are designed to provide generation output at low voltage levels (i.e., less than 1000 V). Should these protection elements fail to remove the generating unit for this scenario, the impacts would be limited to the loss of the individual generating unit and potentially the next device upstream in the collection system of the dispersed power producing resource. However, this would still only result in the loss of a portion of the aggregated capability of the Facility, which would be equally likely to occur due to a scenario in which a fault occurs on the collection system.

Internal faults on the low-voltage system of these generating units would not be discernible on the interconnected transmission systems, as this is similar to a fault occurring on a typical utility distribution system fed from a substation designed to serve customer load. It is important to note that the collection system equipment (e.g., breakers, relays, etc.) used to aggregate the individual units may be relied upon to clear the fault condition in both of the above scenarios, which further justifies ensuring portions of the BES collection equipment is maintained appropriately.

For this reason, activities such as Protection System maintenance on each individual generating unit at a dispersed generation Facility would not provide any additional reliability benefits to the BPS, but Protection System maintenance on facilities where generation aggregates to 75 MVA or more would. The SDT proposes that the scope of PRC-005 be limited to include only the protection systems that operate at a point of aggregation above 75 MVA nameplate rating. If the aggregation point occurs at a component in the collection system, then the protection systems associated with this component would be in scope. *The SDT has recommended changes to the Applicability Section (Facilities) of PRC-005-2, -3, and -4 to indicate that maintenance activities should only apply on the aggregating equipment at or above the point where the aggregation exceeds 75 MVA. The Board approved the SDT's recommended applicability changes to PRC-005-2 and PRC-005-3 on November 13, 2014. The SDT's recommended applicability changes to PRC-005-4 are pending Board approval.*

4.10.8 PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding
PRC-006-SERC -1 — Automatic Underfrequency Load Shedding Requirements

The regional specific PRC-006 standards deviate from the PRC-006-1 standard in that they have specific requirements for GOs. In particular, the NPCC version requires that GOs set their underfrequency tripping to meet certain criteria to ensure reliability of the BPS. Typically, a dispersed generation resource site may have underfrequency protection on both the aggregating equipment (i.e., collection buses or feeders) and the individual generating units. If this standard were only to apply to aggregating equipment, the net impact to the BPS should a system disturbance occur may still result in a loss of significant generating capacity if each of the individual generating units trip for the event. Therefore, it may be appropriate to include the individual generating units at a dispersed generation resource site as subject to this standard. The standard could be interpreted this way as written, but further clarification in the standard language may be considered. While this standard may need to be modified to clarify the applicability for dispersed generation resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

The SERC version of PRC-006 requires GOs to provide, upon request, certain under and overfrequency related set points and other related capabilities of the site relative to system disturbances. It may be appropriate to include the capabilities of the individual generating units at a dispersed generation resource site when providing this information; however, it may be sufficient to provide only the capabilities of a single sample unit within a site, as these units are typically set identically. This would be in addition to any related capabilities or limitations of the aggregating equipment as well. This may be accomplished by providing clarifications in the requirements sections. While this standard may need to be modified to clarify the applicability for dispersed power producing resources, this is a regional standard and not part of the SDT's scope. *Therefore, the SDT recommends that the relevant Region evaluate the standard for modification.*

4.10.9 PRC-015 — Special Protection System Data and Documentation
PRC-016 — Special Protection System Misoperations
PRC-017 — Special Protection System Maintenance and Testing

Relatively few dispersed power producing resources own or operate Special Protection Systems (SPSs); however, they do exist and therefore need to be evaluated for applicability based on the revised BES definition. The vast majority of these SPSs involve the aggregating equipment (transformers, collection

breakers, etc.) and not the individual generating units. The SPSs are installed to protect the reliability of the BPS and, as such, the aggregated response of the site (e.g., reduction in output, complete disconnection from the BES, etc.) is critical—not the response of individual generating units. *Therefore, the applicability of these standards does not need to be changed for dispersed power producing resources.*

4.10.10 PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Dispersed power producing resources typically utilize a site-level voltage control scheme that directs the individual generating units to adjust their output to meet the voltage requirements at an aggregate Facility level. In these cases, the individual generating units will simply no longer respond once they are "maxed out" in providing voltage or reactive changes, but also need to be properly coordinated with protection trip settings on the aggregating equipment to mitigate the risk of tripping in this scenario. Facilities that solely regulate voltage at the individual unit also need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. The applicability in PRC-019-1 (section 4.2.3) includes a "Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating)." *Therefore, the DGR SDT revised the Facilities section of the standard to clarify that facilities which solely regulate voltage at the individual generating unit are subject to this standard's requirements. The SDT's recommended applicability changes to PRC-019-1 were filed with FERC March 13, 2015.*

4.10.11 PRC-023— Transmission Relay Loadability

Dispersed power producing resources in some cases contain facilities and Protection Systems that meet the criteria described in the Applicability section (e.g., load-responsive phase Protection System on transmission lines operated at 200 kV or above); however, in the majority of cases these lines are radially connected to the remainder of the BES and are excluded from the standard requirements of PRC-023-3. While certain entities with dispersed power producing resources are required to meet the requirements of PRC-023 on components of their aggregating equipment (e.g., main step-up transformers, interconnecting transmission lines), the standard is not applicable to the individual generating units, as the individual generating units are addressed in PRC-025. The BES definition changes have no direct impact on the applicability of this standard to dispersed power producing resources. *Therefore, the applicability of this standard does not need to be changed for dispersed power producing resources.*

4.10.12 PRC-024— Generator Frequency and Voltage Protective Relay Settings

If the individual generating units at a dispersed power producing resource were excluded from this requirement, it is possible large portions or perhaps the entire output of a dispersed power producing resource site may be lost during certain system disturbances, negatively impacting BES reliability. The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-BES collection system equipment) are set respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection

systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. *The SDT therefore recommended changes to the standard requirements to ensure these requirements are applied to the individual power producing resources as well as all equipment, potentially including non-BES equipment, from the individual power producing resource up to the point of interconnection and communicated compliance evidence requirement considerations to NERC staff for RSAW development. The SDT's recommended applicability changes to PRC-024 were filed with FERC March 13, 2015.*

4.10.13 PRC-025— Generator Relay Loadability

The Protection System utilized on individual generating units at a dispersed power producing Facility may include load-responsive protective relays and thus would be subject to the settings requirements listed in this standard. If this standard were only to apply to aggregating equipment, the net impact to the BPS if a system disturbance were to occur may be a loss of significant generating capacity if each of the individual generating units trips for the event. The SDT has determined it is appropriate to require that Protection System settings be applied on both the individual generating units at a dispersed power producing resource site as applicable to this standard. However, for the purpose of compliance evidence, the SDT believes it should be sufficient for an entity to provide evidence for a single sample generating unit within a site rather than providing documentation for each individual unit, providing the entity used that methodology to set its protection systems for all the units, rather than providing documentation for each individual unit. This would be in addition to any Protection System settings evidence for the aggregating equipment. As such, the SDT recommends the RSAW be modified as stated above. *The SDT recommended no changes to the standard; however, the DGR SDT communicated compliance evidence requirement considerations to NERC staff for RSAW development.*

4.11 TOP

The TOP standards provide TOPs their authority. Four TOP standards apply directly to GO and GOP entities. The TOP standards as they relate to GOs/GOPs ensure RCs and TOPs can issue directives to the GOP, and the GOP follows such directives. They also ensure GOPs render all available emergency assistance as requested. Finally, they require GO/GOPs to coordinate their operations and outages and provide data and information to the BA and TOP. No TOP standard refers to the interaction of a host BA, TOP, or RC with individual BES Elements.

4.11.1 TOP-001-1a — Reliability Responsibilities and Authorities

This standard as it applies to GOPs is reviewed at the requirement level, with only one change recommended.

4.11.1.1 Requirement R3

The purpose of Requirement R3 as it relates to GOPs is to ensure the RC and TOP reliability directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow an RC or TOP reliability directive, they are to inform the RC or TOP immediately. The requirement is applicable to the registered functional entity, not the constituent

Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed power producing resources from any other GOP resources, and no change to this requirement is needed.*

4.11.1.2 Requirement R6

The purpose of Requirement R6 as it relates to GOPs is to ensure all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements. The requirement is applicable to the registered functional entity, not the constituent Elements it operates. *Therefore, there is no need to differentiate applicability to dispersed power producing resources from any other GOP resources, and no change to this requirement is needed.*

4.11.1.3 Requirement R7

The purpose of Requirement R7 as it relates to GOPs is to ensure BES facilities are not removed from service without proper notification and coordination with the TOP and, when time does not permit such prior notification and coordination, notification and coordination shall occur as soon as reasonably possible. This is required to avoid burdens on neighboring systems. It should be noted that the purpose of this standard is to keep the TOP informed of all generating Facility capabilities in case of an emergency. It is assumed that required notification and coordination from the GOP to the TOP would be done in real time and through verbal communication media. The concern here is how to apply this to a dispersed power producing resource Facility. The SDT recommends that the GOP report at the aggregate Facility level to the TOP any generator outage above 20 MVA for dispersed power producing resource facilities. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition, which addresses only generating units greater than 20 MVA.
- TOP-002-2.1b Requirement R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the Facility (e.g., 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Dispersed power producing resource outages should be reported as "x MW out of y MW are available." *Therefore, the SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for generator outages greater than 20 MVA.*

4.11.2 TOP-001-3 — Transmission Operations[22]

The purpose of this standard as it relates to GOPs is to ensure TOP directives are complied with so long as they do not violate safety, equipment, or regulatory or statutory requirements. If a GOP is unable to follow a TOP directive, it is to inform the TOP immediately. It directs the TOP to issue directives, and as such, the TOP may provide special requirements for dispersed power producing resources for its unique

[22] Note that TOP-001-2 was adopted by the Board and remanded by FERC. TOP-001-2 is currently under revision as part of Project 2014-03 – Revisions to TOP and IRO Standards, and was posted for additional ballot period that is scheduled to close January 7, 2015 as TOP-001-3.

capabilities. *The SDT recommended that Project 2014-3 provide direction for a dispersed power producing resource to be only reported at the aggregate facility level.*

4.11.3 TOP-002-2.1b — Normal Operations Planning[23]

This TOP standard has five requirements applied to GOPs. Several modifications are recommended below, and the SDT recommends that the most effective and efficient way to accomplish this is through modification of the Applicability section of this standard.

4.11.3.1 Requirement R3

The purpose of Requirement R3 as it relates to GOPs is to ensure a GOP's current-day, next-day and seasonal operations are coordinated with its host BAs and TSP. This requirement relates to planned operations at a generator and does not include unplanned operations such as forced or emergency operations. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources. For example, forecasting available megawatts at the aggregated Facility level is currently one method used. The SDT does not see any reliability gap that would prompt this team to apply R3 to any point less than the dispersed power producing resource aggregated Facility level.

The SDT has not found or been made aware of a reliability gap that would prompt this team to apply R3 to any point less than the dispersed power producing resource aggregated Facility level and recommends such modification to the applicability of this requirement.

4.11.3.2 Requirement R13

The purpose of Requirement R13 as it relates to GOPs is to ensure Real Power and Reactive Power capabilities are verified as requested by the BA and TOP. The SDT believes a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources for the following reasons:

- Due to the nature, amount of individual generators at a dispersed power producing resource, internal Real Power losses, and natural inductance and capacitance of dispersed power resource system connected in series, verification of real and reactive capabilities should be conducted at the dispersed power producing resource aggregate Facility level. Performing verification in this manner will provide an actual net real and reactive capability, which would be seen by both the BA and TOP. In addition, performing verification in this manner is also consistent with operating agreements such as an interconnection agreement, which the dispersed power resource has with the TOP and BA.
- MOD-025-2 also provides that verification for any generator less than 20 MVA may be completed on an individual unit basis or as a "group." Reporting capability at the aggregated Facility level is consistent with the MOD-025-2 provision for group verification.

[23] The GOP applicability is removed in TOP-002-3, which was adopted by the Board. However, TOP-002-3 was included in the proposed remand by FERC and is subject to revision as part of Project 2014-3 – Revisions to TOP and IRO standards.

The SDT recommends a modification to the applicability of this requirement at the aggregated Facility level for dispersed power producing resources.

4.11.3.3 Requirement R14

The purpose of Requirement R14 as it relates to GOPs is to ensure BAs and TOPs are notified of changes in real output capabilities without any intentional time delay. It should be noted that the purpose of this requirement is to address unplanned changes in real output capabilities. It is assumed the required notification and coordination from the GOP to the BA and TOP would be done in real time and through verbal communication media. The concern here is how to apply this to dispersed power producing resources. The SDT recommends that the GOP notify at the aggregate Facility level to the TOP any unplanned changes in real output capabilities above 20 MVA. The justification is based on the following:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20 MVA; and
- TOP-002-2.1b R14 requires real-time notification of changes in Real Power capabilities, planned and unplanned. Setting the threshold at 20 MVA would address routine maintenance on a small portion of the Facility (e.g. 2% of the generators are out of service on any given day) and individual generating units going into a failure. Otherwise, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.

Changes in the real output capabilities of dispersed generation resources should be reported as "x MW out of y MW are available." *The SDT recommends that a modification to the applicability of this requirement is necessary for dispersed power producing resources for unplanned outages greater than 20 MVA.*

4.11.3.4 Requirement R15

The purpose of Requirement R15 as it relates to GOPs is to ensure BAs and TOPs are provided a forecast (e.g., seven days) of expected Real Power. The SDT believes this requirement as requested by the BA or TOP is being applied at the aggregate Facility level for dispersed power producing resources.

Based on the SDT's experience, expected Real Power forecasts (e.g., five- or seven-day forecast) for a dispersed power producing resource traditionally have been coordinated with the BA and TOP at the aggregate Facility level for dispersed power producing resources. *Therefore, the SDT recommends that R15 be applied at the aggregate Facility level for dispersed power resources and, as such, modification to the applicability of this requirement is necessary.*

4.11.3.5 Requirement R18

The purpose of Requirement R18 as it relates to a GOP is to ensure uniform line identifiers are used when referring to transmission facilities of an interconnected network. The standard applies to transmission facilities of an interconnected network, which would not apply to any Elements within the dispersed generation Facility. There is no need to differentiate applicability to dispersed generation resources from any other GOP resources. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

4.11.4 TOP-003-1— Planned Outage Coordination

This TOP Standard has three requirements applied to GOPs. Modification to one of these requirements is recommended.

4.11.4.1 Requirement R1

The purpose of Requirement R1 as it relates to GOPs is to ensure TOPs are provided planned outage information on a daily basis for any scheduled generator outage greater than 50 MW for the next day. *Therefore, the applicability of this requirement does not need to be changed for dispersed generation resources.*

4.11.4.2 Requirement R2

The purpose of Requirement R2 as it relates to GOPs is to ensure all scheduled outages of voltage-regulating equipment are planned and coordinated with affected BAs and TOPs. A modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT recommends that this requirement be applied at the aggregate Facility level for dispersed power producing resources.

Based on the SDT's experience, scheduled outages of voltage-regulating equipment at a dispersed power producing resource traditionally has been provided to the BA and TOP at the aggregate Facility level for dispersed power producing resources. Outages of voltage-regulating equipment at a dispersed power producing resource are coordinated typically as a reduction in Reactive Power capabilities, specifying whether it is inductive, capacitive, or both. Additionally, automatic voltage regulators that do not necessarily provide Reactive Power, but direct the actions of equipment that do supply Reactive Power, are typically coordinated at the aggregate Facility level as they usually are the master controller for all voltage-regulating equipment at the Facility. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap that would prompt this team to apply R2 to any point less than the dispersed power producing resource aggregated Facility level and, as such, determined a modification to the applicability of this requirement is necessary for dispersed power producing resources.*

4.11.4.3 Requirement R3

The purpose of Requirement R3 as it relates to GOPs is to ensure scheduled outages of telemetering and control equipment and associated communication channels are planned and coordinated among BAs and TOPs. Based on the SDT's technical expertise, scheduled outages of telemetering and control equipment and associated communication channels at a dispersed power producing resource traditionally have been provided to the BA and TOP at the aggregate Facility level. In addition, only scheduled outages of telemetering and control equipment and associated communication channels that can affect the BA and TOP are coordinated with the BA and TOP. *Therefore, the applicability of this requirement does not need to be changed for dispersed power producing resources.*

4.11.5 TOP-006 — Monitoring System Conditions

The purpose of this standard as it relates to GOPs is to ensure BAs and TOPs know the status of all generation resources available for use as informed by the GOP. It should also be noted that the purpose of this standard is to ensure that critical reliability parameters are monitored in real time. It then can be extrapolated that the requirement, "GOP shall inform…," is done by sending dispersed power producing

resource telemetry in real time and through a digital communication medium, such as an ICCP link or RTU. The SDT concludes that a modification to the applicability of this requirement is necessary for dispersed power producing resources. The SDT is recommending that this requirement be applied at the aggregate Facility level for dispersed power producing resources for the following reasons:

- This is consistent with Inclusion I2 of the revised BES definition, which includes generating units greater than 20 MVA. If removing "less than 20 MVA" would cause a burden to the BPS, then the threshold for inclusion in the BES would have been less than 20 MVA.
- Routine maintenance is frequently completed on a small portion of the entire Facility (e.g. 2% of the generators are out of service on any given day) such as to not have a significant impact to the output capability of the Facility. Additionally, it is not uncommon to have individual generating units at a dispersed power producing resource to go into a failure mode due to internal factors of the equipment, such as hydraulic fluid pressure tolerances, gearbox-bearing thermal tolerances, etc. As such, coordinating each individual generating unit outage would burden the TOP without providing an increase in reliability to the interconnected BPS.
- As this standard requires real-time monitoring, this is most likely completed through a digital medium such as an ICCP link or RTU. The data that a dispersed power resource provides to the BA and TOP in real time should include the aggregate active power output of the Facility, among other telemetry points. These data specifications are usually outlined in interconnection agreements among the parties.

Based on the SDT's technical expertise, BAs and TOPs are informed by the GOP of all generation resources available at the dispersed power producing resource at the aggregate Facility level. Traditionally the dispersed power producing resources provide the BA and TOP, at minimum, the following telemetry points in real time: aggregate Real Power, aggregate Reactive Power, and main high-side circuit breaker status. A key aspect of the SDT project is to maintain the status quo, if it is determined not to cause a reliability gap. *The SDT has not found or been made aware of a reliability gap that would prompt this team to apply these requirement to any point less than where the dispersed power producing resource aggregates and, as such, recommends a modification to the applicability of this requirement for dispersed power-producing resources.*

4.12 TPL

At the time of this paper, these standards do not affect GOs or GOPs directly. Input from GO or GOP entities is provided to transmission planning entities through the MOD standards. *Therefore, the applicability of the TPL standards does not need to be changed for dispersed power producing resources.*

4.13 VAR

The VAR standards exist to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained. Two VAR standards apply to GOs and/or GOPs. The voltage and/or reactive schedule provided by TOPs is specified to be at the point of interconnection or the point specified in the interconnection agreement.

4.13.1 VAR-001 — Voltage and Reactive Control (WECC Regional Variance)

The purpose of this standard as it relates to GOPs in WECC is to ensure a generator voltage schedule is issued that is appropriate for the type of generator(s) at a specific Facility. Additionally, it requires GOPs to have a methodology for how the voltage schedule is met, taking into account the type of equipment used to maintain the voltage schedule. Based on the SDT's technical expertise, voltage control and voltage schedule adherence for dispersed power producing resources occurs at the aggregate Facility level. There is no need to differentiate dispersed generation resources from any other GOP resources. *Therefore, the applicability of VAR-001 does not need to be changed for dispersed generation resources.*

4.13.2 VAR-002-2b — Generator Operation for Maintaining Network Voltage Schedules
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

The purpose of these standards as they relate to GOs and GOPs is to ensure generators operate in automatic voltage control mode as required by the TOP voltage or reactive power schedule provided to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the SDT's technical expertise, voltage control and voltage schedule adherence for dispersed power producing resources occurs at the aggregate Facility level, and such guidance should be provided.

In addition, the voltage-controlling equipment and the methodology to ensure the Facility has an automatic and dynamic response to ensure the TOP's instructions are maintained can be very different for each Facility. It is implied in VAR-001-3 that each TOP should understand capabilities of the generation Facility and the requirements of the transmission system to ensure that a mutually agreeable solution/schedule is used.

4.13.3 VAR-002-2b — Requirement R3.1
VAR-002-3 — Requirement R4

The purpose of these requirements is to ensure that a GOP notifies the TOP, within 30 minutes, of any status and capability changes of any generator Reactive Power resource, including automatic voltage regulator, power system stabilizer, or alternative voltage controlling device. Based on the experience of the SDT, status and capability changes are traditionally coordinated at the aggregate Facility level point of interconnection. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R3.1 and VAR-002-3 R4 for dispersed power-producing resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*

4.13.4 VAR-002-2b — Requirement R4
VAR-002-3 — Requirement R5

The purpose of these requirements is to ensure that Transmission Operators and Transmission Planners have appropriate information and provide guidance to the GOP in regard to Generator Operators' transformers to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and reliability of the Interconnection. Based on the experience of the SDT, dispersed power producing resources' individual generator transformers traditionally have been excluded from the requirements of VAR-002-2b R4 and VAR-002-3 R5, as they

are not used to improve voltage performance on the Interconnection. As such, applicability should be limited to transformers with at least one winding at a voltage of 100 kV or above. *Therefore, the SDT has recommended changes to the standard to clarify the applicability of VAR-002-2b R4 and VAR-002-3 R5 for dispersed generation resources. These changes were successfully balloted in VAR-002-4 on November 6, 2014, and approved by the Board on November 13, 2014.*

4.14 CIP

4.14.1 CIP Version 5

The CIP standards are still under revision in Project 2014-02. The DGR SDT and the CIP SDT continue to coordinate revisions to the CIP standards and will update this section to reflect the outcome of that effort at the appropriate time.

The CIP standards ensure physical and cyber security for BES Cyber Assets and BES Cyber Systems critical to the reliability and security of the BES. CIP-002 identifies critical assets or systems of a Facility, while CIP-003 to CIP-011 depend on the outcome of the CIP-002 assessment to determine applicability.

During the first comment period for the Project 2014-02 CIP Version 5 Revisions, the SDT received comments to modify CIP-003-6 in the Applicability section. The CIP SDT made significant modifications to the second posting of CIP-003-6 to take into account all of the comments received. This was posted for an additional 45-day comment and ballot period on September 3, 2014.

At its September meeting, the DGR SDT had a focused discussion with the CIP SDT surrounding the technical nature of the dispersed power producing resources and how it relates to the CIP standards. The coordinating effort resulted in discussions of the revised CIP-003-6. As for that posted revised standard, the CIP SDT took the approach of including an Attachment 1 for Responsible Entities. Attachment 1 requires elements to be developed in Responsible Entities' cybersecurity plans for assets containing low-impact BES cyber systems. The elements in CIP-003-6, Attachment 1 allow flexibility for the controls to be established for each of the main four elements below. The CIP SDT encourages observers of the DGR SDT to review Attachment 1 in detail. Below is some information regarding the attachment.

Element 1: Security Awareness

The intent of the security awareness program is for entities to reinforce good cybersecurity practices with their personnel at least once every 15 calendar months. The entity decides the topics and how it schedules them. The Responsible Entity should be able to produce the awareness material that was delivered and the delivery method(s) (posters, emails, topics at staff meetings, etc.) that were used. The SDT does not intend that the Responsible Entity must maintain lists of recipients and track the reception of the awareness material by personnel.

Element 2: Physical Security

The Responsible Entity has flexibility in the controls used to restrict physical access to low-impact BES Cyber Systems at a BES asset using one or a combination of access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may utilize perimeter controls (e.g., fences with locked gates, guards, site access policies, etc.) and/or more granular areas of physical

access control in areas where low-impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of authorized users are not required.

Element 3: Electronic Access Controls

Where Low Impact External Routable Connectivity (LERC) or Dial-up Connectivity exists, the Responsible Entity must document and implement controls that include the LERC and Dial-up Connectivity to the BES asset such that the low-impact BES Cyber Systems located at the BES asset are protected. Two glossary terms are included in order to help clarify and simplify the language in Attachment 1. The SDT's intent in creating these terms is to avoid confusion with the similar concepts and requirements (ESP, EAP, ERC, EACMS) needed for high- and medium-impact BES Cyber Systems by using separate terms that apply only to assets containing low-impact BES Cyber Systems.

Element 4: Cyber Security Incident Response

The entity should have one or more documented cybersecurity incident response plan that includes each of the topics listed. For assets that do not have LERC, it is not the intent to increase their risk by increasing the level of connectivity in order to have real-time monitoring. The intent is, if in the normal course of business suspicious activities are noted at an asset containing low-impact BES Cyber Systems, a cybersecurity incident response plan will guide the entity through responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Therefore, the DGR SDT recommends that no changes be made to the proposed CIP-003-6. CIP-002-5.1 needs to remain as is, because entities must go through the process for identifying and categorizing their BES Cyber Systems and associated BES Cyber Assets. The controls put in place for proposed CIP-003-6, Attachment 1, are not burdensome, are realistic and achievable, and do not express undue compliance burden. In conclusion, the DGR SDT states that the reliability objective of these controls is adequate and the applicability of CIP-003-6 should not be modified.

The SDT states that the CIP Version 5 Revisions SDT should consider developing guidance documentation around the following areas:

- Low-impact BES Cyber Systems that must comply with a limited number of requirements, all located in CIP-003-5. The only technical requirement is R2, which will be modified during the current drafting activity to add clarity to the requirement. The SDT notes that the CIP Version 5 Revisions SDT should consider developing guidance around how this requirement relates to dispersed generation.
- Any programmable logic device that has the capability to shut down the plant within 15 minutes.
- Remote access from third-party entities into the SCADA systems that control the aggregate capacity of a Facility should be assessed to determine if there is a need of any additional cybersecurity policies.

The SDT intends to recommend guidance for those companies that only operate their turbines from one central location. Individual Elements lumped into a BES Cyber System should be addressed. When operations are on a turbine-by-turbine basis, the SDT believes there should not be rigid controls in place. The inability to "swim upstream" should be addressed as well. Further, the guidance intends to address when manufacturers operate or have control of the SCADA environment to conduct troubleshooting and other tasks, and ensure that proper security is in place.

NERC staff has committed to facilitate communication between the SDT and the CIP Version 5 Revisions SDT as appropriate to ensure alignment and to develop language for guidance, coordinated between the two SDTs. *Therefore, the applicability of CIP standards does not need to be changed for dispersed generation resources.*

Appendix A: List of Standards

Appendix B: List of Standards Recommended for Further Review

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the Bulk-Power System through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Internal Communications Capabilities		
Date Submitted:	June 10, 2015		
SAR Requester Information			
Name:	Ryan Stewart		
Organization:	NERC		
Telephone:	404-446-9712	E-mail:	Ryan.Stewart@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
The purpose of the proposed project is to address the directive from FERC Order No. 808 to modify the COM-001-2 standard or develop a new standard to address "internal communications capabilities that could involve the issuance or receipt of Operating Instructions or other communications that could have an impact on reliability." Order No. 808, at P 1. See quotes below from Order No. 808, at P 41 for more specificity within FERC's directive.

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On April 16, 2015, FERC issued Order No. 808, Communications Reliability Standards. In this order, FERC approved COM-001-2 and also directed that NERC to either develop a new standard or make the following modification to the existing COM-001-2 standard: > [FERC] direct[s] NERC to develop modifications to COM-001-2, or to develop a new standard, to address our concerns regarding ensuring the adequacy of internal communications capability whenever internal communications could directly affect the reliable operation of the Bulk-Power System. > Order No. 808, at P 41. FERC's directive thus encompasses a directive that the modified or new standard: > address the adequacy of internal telecommunications (or other internal communication systems) that may have an adverse effect on reliability, even within a single functional entity, including: (1) communications between geographically separate control centers within the same functional entity; and (2) communications between a control center and field personnel. These scenarios present a gap in reliability of the Bulk-Power System that NERC should address. > *Id.*
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The proposed project will develop a new standard or modify existing requirements in COM-001-2 to address the directive from FERC Order No. 808, including its subparts. *See* Order No. 808, at PP 1, 41.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
As stated above, the purpose of the proposed project is to respond to the directive in FERC Order No. 808. The following is a description of the responses the standard drafting team (SDT) shall consider during development of the new or modified standards: • The SDT shall address internal telecommunications or other internal communication systems "between geographically separate control centers within the same functional entitiy." Order No. 808, at P 41.

SAR Information
• The SDT shall address internal telecommunications or other internal communication systems "between a control center and field personnel." *Id.* • The SDT shall address "[t]he adequacy of internal communications capability whenever internal communications could directly affect the reliable operation of the Bulk-Power System." *Id.* • The SDT shall address "internal communications capabilities that could involve the issuance or receipt of Operating Instructions or other communications that could have an impact on reliability." Order No. 808, at P 1.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.

Reliability Functions		
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected Bulk-Power Systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected Bulk-Power Systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected Bulk-Power Systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected Bulk-Power Systems.
☒	6. Personnel responsible for planning and operating interconnected Bulk-Power Systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Reliability and Market Interface Principles	
☐	7. The security of the interconnected Bulk-Power Systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

151 FERC ¶ 61,039
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM14-13-000; Order No. 808]

Communications Reliability Standards

(Issued April 16, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Pursuant to the Federal Power Act, the Commission approves two revised Reliability Standards, COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols), developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. The two revised Reliability Standards will enhance reliability by, among other things, requiring adoption of predefined communication protocols, annual assessment of those protocols and operating personnel's adherence thereto, training on the protocols, and use of three-part communications. In addition, the Commission directs NERC to develop a modification to Reliability Standard COM-001-2 that addresses internal communications capabilities that could involve the issuance or receipt of Operating Instructions or other communications that could have an impact on reliability.

DATES: This rule will become effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**.

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SUPPLEMENTARY INFORMATION:

151 FERC ¶ 61,039
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

Communications Reliability Standards Docket No. RM14-13-000

ORDER NO. 808

FINAL RULE

(Issued April 16, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves two Reliability Standards, COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols), developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. The Commission also approves three new defined terms for addition to the NERC Glossary of Terms Used in Reliability Standards (NERC Glossary), violation risk factors, violation severity levels, and NERC's proposed implementation plan for both revised standards. Further, pursuant to section 215(d)(5) of the FPA, the Commission directs that NERC develop one modification to Reliability

[1] 16 U.S.C. 824o (2012).

Standard COM-001-2 that addresses internal communications capabilities to the extent that such communications could involve the issuance or receipt of Operating Instructions or other communications that could have an impact on reliability.

2. Reliability Standard COM-001-2 is intended to establish a clear set of requirements for the communications capabilities that applicable functional entities must have in place and maintain. Reliability Standard COM-002-4 requires applicable entities to develop communication protocols with certain minimum requirements, including use of three-part communication when issuing Operating Instructions.[2] Reliability Standard COM-002-4 also sets out certain communications training requirements for all issuers and recipients of Operating Instructions, and establishes a flexible enforcement approach for failure to use three-part communication during non-emergencies and a "zero-tolerance," i.e., without exception, enforcement approach for failure to use three-part communication during an emergency.[3]

3. We find that Reliability Standards COM-001-2 and COM-002-4 will enhance reliability over the currently-effective versions of these Communications (COM)

[2] NERC proposes to define Operating Instruction as "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives . . . is not considered an Operating Instruction.)."

[3] *See* NERC Petition at 3 ("during Emergencies, operating personnel must use the documented communication protocols for three-part communications without exception.").

standards in several respects. For example, the Reliability Standards as modified expand applicability to include generator operators and distribution providers, eliminate certain ambiguities in the currently-effective standards, and clarify that the use of three-part communication is required for issuance and receipt of all Operating Instructions, with a zero-tolerance approach to enforcement of that requirement during an emergency. However, we are not persuaded that COM-001-2 adequately covers all situations in which Operating Instructions are issued or received and, therefore, direct NERC to develop a modification to that standard that addresses our concern, as further discussed below.

I. Background

A. Regulatory Background

4. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[4] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight, or by the Commission

[4] 16 U.S.C. at 824o(c) and (d).

independently.[5] In 2006, the Commission certified NERC as the ERO pursuant to FPA section 215.[6]

5. The Commission approved Reliability Standard COM-001-1 in Order No. 693.[7] In addition, the Commission directed NERC to develop modifications to COM-001-1 to: (1) expand the applicability of the standard to include generator operators and distribution providers, (2) identify specific requirements for telecommunications facilities for use in normal and emergency conditions that reflect the roles of the applicable entities, and (3) include adequate flexibility for compliance to allow for the adoption of new technologies and cost-effective solutions.[8] Similarly, the Commission approved Reliability Standard COM-002-2 in Order No. 693. In addition, the Commission directed NERC to develop modifications to (1) include distribution providers as applicable entities, and (2) establish tightened communications protocols, especially for communications during alerts and emergencies.[9]

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[5] *See id.* at 824o(e).

[6] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[7] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 508, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007); *see also North American Electric Reliability Corp.*, Docket No. RD09-2-000 (2009) (delegated letter order accepting Reliability Standard COM-001-1.1).

[8] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 508.

[9] *Id.* PP 531-535, 540.

6. NERC initiated Project 2006-06 to address the Order No. 693 directives related to Reliability Standards COM-001 and COM-002, resulting in two proposed Reliability Standards, COM-001-2 and COM-002-3. NERC also initiated Project 2007-02 to develop a new Reliability Standard (COM-003) that would require real-time system operators to use standardized communication protocols during normal and emergency operations, in order to improve situational awareness and shorten response time. The two projects ultimately merged when drafts of Reliability Standard COM-002-3 and COM-003-1 were combined into a single proposed Reliability Standard, COM-002-4.

B. NERC Petition

7. On May 14, 2014, NERC filed a petition seeking approval of two revised communication standards, COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols).[10] Proposed Reliability Standard COM-001-2 establishes a set of requirements for the communications capabilities that various functional entities must maintain to enable communications with other identified functional entities. Proposed Reliability Standard COM-002-4 requires applicable entities to develop documented communications protocols. NERC stated in its petition that the proposed standards are intended to address all relevant Commission directives

[10] The COM Reliability Standards are not attached to the Final Rule. The complete text of the two Reliability Standards is available on the Commission's eLibrary document retrieval system in Docket No. RM14-13 and is posted on the ERO's web site, *available at*: http://www.nerc.com.

from Order No. 693. In addition, NERC stated that the revisions reflected in proposed COM-002-4 are intended to address Recommendation No. 26 from the final report on the August 2003 blackout issued by the U.S.-Canada Power System Outage Task Force (Blackout Report) concerning the need to "[t]ighten communications protocols, especially for communications during alerts and emergencies."[11]

Reliability Standard COM-001-2

8. NERC stated in its petition that Reliability Standard COM-001-2 establishes requirements for Interpersonal Communication capabilities necessary to maintain reliability. NERC explained that proposed Reliability Standard COM-001-2 applies to reliability coordinators, balancing authorities, transmission operators, generator operators, and distribution providers. The proposed Reliability Standard includes eleven requirements and two new defined terms, "Interpersonal Communication" and "Alternative Interpersonal Communication," that, according to NERC, collectively provide a comprehensive approach to establishing communications capabilities necessary to maintain reliability.[12] NERC stated that the definitions provide clarity that an entity's

[11] NERC Petition at 3 (quoting *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* at 3 (April 2004) (Blackout Report), *available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf).

[12] *Id.* at 15. NERC defines Interpersonal Communication as "[a]ny medium that allows two or more individuals to interact, consult, or exchange information" and Alternative Interpersonal Communication as "[a]ny Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation." *Id.*

communication capability must be redundant and that each of the capabilities must not utilize the same medium. According to NERC, the definitions improve the language used in the current Reliability Standard by eliminating the use of the more ambiguous phrases "adequate and reliable" and "redundant and diversely routed" that relate to "telecommunications facilities for the exchange of Interconnection and operating information."[13]

9. The first six requirements of COM-001-2 address the Interpersonal Communication capability and Alternative Interpersonal Communication capability of the reliability coordinator, transmission operator, and balancing authority functions. Requirement R1 requires each reliability coordinator to have Interpersonal Communication capability with all transmission operators and balancing authorities within its reliability coordinator area, and with each adjacent reliability coordinator within the same interconnection. Requirement R2 requires each reliability coordinator to designate Alternative Interpersonal Communication capability with those same identified entities. Requirements R3 and R4 set out the communications capability requirements for a transmission operator. Under Requirement R3, Interpersonal Communication capability is required between the transmission operator's reliability coordinator, each balancing authority within its transmission operator area, each distribution provider and generator operator within its transmission operator area, and each adjacent transmission

[13] *Id.* at 15-16.

operator whether synchronously or asynchronously connected. Under Requirement R4, Alternative Interpersonal Communication capability must be designated between the transmission operator's reliability coordinator, each balancing authority within its transmission operator area, and each adjacent transmission operator. Requirements R5 and R6 set out similar requirements for each balancing authority, again identifying the specific functional entities for which the balancing authority must maintain Interpersonal Communication capability and for which it must designate Alternative Interpersonal Communication capability.

10. Requirements R7 and R8 address the communications capability that distribution providers and generator operators must maintain, with each required to have Interpersonal Communications capability with its balancing authority and its transmission operator.

11. Requirement R9 requires each reliability coordinator, transmission operator, and balancing authority to test its Alternative Interpersonal Communication capability at least once each calendar month, and to initiate action to repair or designate a replacement if the test is unsuccessful. Requirement R10 requires the same entities to notify applicable entities (as identified in R1, R3 and R5) of the detection of an Interpersonal Communication capability failure that lasts 30 minutes or longer. Finally, Requirement R11 requires distribution providers and generator operators to consult with affected balancing authorities and transmission operators when a failure is detected in their Interpersonal Communication capability, and to determine a mutually agreeable action for the restoration of that capability.

12. NERC stated in its petition that proposed Reliability Standard COM-001-2 improves the currently-effective Reliability Standard by: (1) eliminating terms that do not adequately specify the desired actions that applicable entities are expected to take in relation to their telecommunication facilities; (2) clearly identifying the need for applicable entities to be capable of Interpersonal Communication and Alternative Interpersonal Communication; (3) not requiring specific technology or systems to be utilized; and (4) including the distribution provider and generator operator as applicable entities.[14] NERC added that COM-001-2 also addresses relevant directives from Order No. 693 by (1) adding generator operators and distribution providers as applicable entities; (2) identifying specific requirements for telecommunications capabilities for use in all operating conditions that reflect the roles of the applicable entities and their impact on reliability; and (3) including adequate flexibility to permit the adoption of new technologies.

13. NERC proposed to retire currently-effective COM-001-1.1 when proposed Reliability Standard COM-001-2 becomes effective, with the exception of Requirement R4, which addresses communications protocols. NERC requested that Requirement R4 be retired when proposed Reliability Standard COM-002-4 becomes effective.[15]

[14] NERC Petition at 18.

[15] *Id.* at 22.

Reliability Standard COM-002-4

14. NERC stated in its petition that Reliability Standard COM-002-4 improves communications surrounding the issuance of Operating Instructions by requiring the use of predefined communications protocols to reduce the possibility of miscommunication that could lead to action or inaction harmful to reliability.[16] NERC noted that the proposed standard requires use of the same protocols regardless of operating condition (i.e., Emergency or non-emergency), but requires operating personnel to use the documented communication protocols for three-part communications "without exception" during an Emergency.[17] As NERC explained:

> [T]he proposed Reliability Standard employs the phrase "Operating Instruction during an Emergency" in certain requirements (R5, R6, R7) to provide a demarcation for what is subject to a zero-tolerance compliance approach and what is not.[18]

[16] *Id.* at 23. NERC stated that COM-002-3 (which was adopted by the NERC Board but not submitted to the Commission for approval) is proposed for retirement in the Implementation Plan because the proposed Reliability Standard has been combined with proposed COM-003-1 to create proposed Reliability Standard COM-002-4. NERC stated that Reliability Standard COM-002-3 has not been submitted to the Commission for approval, therefore, the currently effective version of COM-002 is COM-002-2. *Id.* at 23 n.43. Reliability Standard COM-002-4 combines proposed Reliability Standard COM-002-3 and the former draft COM-003-1 into a single standard that addresses communications protocols for operating personnel in Emergency and non-emergency conditions. *Id.* at 23-24.

[17] *Id.* at 3.

[18] *Id.* at 25.

NERC explained that, for Operating Instructions issued during non-emergency operations, "an entity will be assessed under a compliance approach that focuses on whether an entity meets the initial training Requirement (either R2 or R3) and whether an entity performed the assessment and took corrective actions according to Requirement R4."[19]

15. Finally, NERC stated that the proposed Reliability Standard includes distribution providers and generator operators as applicable entities, in accordance with the Commission's directive in Order No. 693, and in recognition of the fact that these types of entities can be recipients of Operating Instructions.

16. Proposed Reliability Standard COM-002-4 includes seven requirements. Requirement R1 requires entities that can both issue and receive Operating Instructions (balancing authorities, reliability coordinators and transmission operators) to have documented communications protocols that include a minimum set of elements, including use of the English language unless otherwise specified, and required use of three-part communications for issuance and receipt of Operating Instructions.[20] Requirement R2 requires these same entities to conduct initial training on the communications protocols for each of their operating personnel responsible for the real-time operation of the bulk electric system. Requirement R3 requires distribution

[19] *Id.* at 26.

[20] *See id*. at 29.

providers and generator operators (who generally only receive but do not issue Operating Instructions) to conduct initial training on three-part communication for each of their operating personnel who can receive an oral two-party, person-to-person Operating Instruction, prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction.

17. Requirement R4 requires each balancing authority, reliability coordinator and transmission operator to assess, at least once every twelve months, its operating personnel's adherence to the documented communication protocols required in Requirement R1, and to provide feedback to its operating personnel on their performance.

18. Requirement R5 requires balancing authorities, reliability coordinators and transmission operators that issue an oral two-party, person-to-person "Operating Instruction during an Emergency" to use three-part communication, and to take an alternative action if a confirmation is not received. Requirement R6 requires all applicable entities (balancing authorities, distribution providers, generator operators, and transmission operators) that receive an oral two-party, person-to-person "Operating Instruction during an Emergency" to use three-part communication, i.e., to repeat the Operating Instruction and receive confirmation from the issuer that the response was correct, or request that the issuer reissue the Operating Instruction. Both Requirement R5 and R6 include the clarification that the requirement does not apply to single-party to multiple-party "burst" Operating Instructions. As noted above, NERC explains that Requirements R5 and R6 require use of three-part communication during an Emergency without exception, because "use of three-part communication is critically important if an

Emergency condition already exists, as further action or inaction could increase the harmful effects to the Bulk Electric System."[21] NERC further explains, however, that applicable entities are expected to use three-part communications at all times when issuing and receiving Operating Instructions.[22]

19. Finally, Requirement R7 requires that when a balancing authority, reliability coordinator, or transmission operator issues a written or oral single-party to multiple-party "burst" Operating Instruction during an Emergency, they must confirm or verify that at least one receiver received the Operating Instruction.

20. NERC requested that proposed Reliability Standard COM-002-4 become effective on the first day of the first calendar quarter that is twelve months after the date that the standard is approved.

C. Notice of Proposed Rulemaking

21. On September 19, 2014, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve Reliability Standards COM-001-2 and COM-002-4 pursuant to FPA section 215(d)(2), along with the three new definitions referenced in the proposed standards (Operating Instruction, Interpersonal Communication, and

[21] *Id.* at 39.

[22] *Id.* at 25-26.

Alternative Interpersonal Communication), the assigned violation risk factors and violation severity levels, and the proposed implementation plan for each standard.[23]

22. In the NOPR, the Commission explained that the two revised standards addressed outstanding directives from Order No. 693, in that COM-001-2 has been expanded to include distribution providers and generator operators, and COM-002-4 has been expanded to include distribution providers.[24] The Commission also stated that Reliability Standard COM-002-4 would enhance reliability by providing for improved communications through the required development of communication protocols.

23. In the NOPR, the Commission also discussed the following specific matters and asked for further comment: (1) responsibility for use of three-part communication by transmission owners and generator owners that receive Operator Instructions; (2) whether COM-001-2 should be modified to address internal communication capability requirements, or to address testing requirements for distribution providers and generator operators; and (3) clarifications regarding the proposed terms Interpersonal Communication and Alternative Interpersonal Communication.

24. Timely comments on the NOPR were filed by: NERC; the Edison Electric Institute and the Electric Power Supply Association (EEI/EPSA); ISO/RTO Council; the National Rural Electric Cooperative Association (NRECA); International Transmission

[23] *Communications Reliability Standards,* Notice of Proposed Rulemaking, 79 FR 58709 (Sept. 30, 2014), 148 FERC ¶ 61,210 (2014) (NOPR).

[24] *Id.* PP 22, 23.

Company (ITC); Idaho Power Company (Idaho Power); and Tri-State G&T. In addition, on March 6, 2015, NERC filed Supplemental Comments.

II. Discussion

25. Pursuant to section 215(d)(2) of the FPA, we adopt our NOPR proposal and approve Reliability Standards COM-001-2 and COM-002-4, including the associated definitions, violation risk factors, violation severity levels, and implementation plans, as just, reasonable, not unduly discriminatory or preferential and in the public interest. We note that all of the commenters that addressed the overall value of the Reliability Standards supported, or did not oppose, approval of the two revised standards. We determine that COM-001-2 will enhance reliability by expanding the applicability of currently effective COM-001-1.1 to include generator operators and distribution providers as applicable entities under the COM-001 standard, and by expanding the applicability of COM-002-4 to include distribution providers. We further find that COM-002-4 will enhance reliability by requiring all issuers and recipients of Operating Instructions to develop communications protocols that require use of three-part communications, by requiring training on those protocols, and by adopting a zero-tolerance enforcement approach to the use of three-part communications during an Emergency. Moreover, we conclude that requiring issuers of Operating Instructions to perform an annual assessment of their personnel's adherence to the communications protocols will help ensure a high level of compliance with three-part communications at all times.

26. Pursuant to section 215(d)(5) of the FPA, the Commission directs that NERC develop one modification to COM-001-2 to address our concerns regarding applicability to certain internal communications, as discussed below.

27. Below, we discuss the following matters: (A) ensuring use of three-part communications by generator owners and transmission owners; (B) internal communication capability requirements; (C) testing requirements for distribution providers and generator operators; and (D) scope of the terms Interpersonal Communication and Alternative Interpersonal Communication.

A. Applicability to Generator Owners and Transmission Owners

NOPR

28. In the NOPR, the Commission raised the concern that generator owners and transmission owners are not "applicable entities" under either COM-001-2 or COM-002-4, although these entities could, under some circumstances, receive and act on Operating Instructions.[25] The Commission sought comment on the obligations of an applicable entity when issuing an Operating Instruction to a transmission owner or generator owner, including information regarding which entity is responsible if the transmission owner or generator owner fails to perform three-part communication properly. In addition, the Commission asked NERC to explain its auditing practices when reviewing operating agreements between transmission operators and transmission owners, and between

[25] *See id.* PP 25-27.

generator operators and generation owners, including NERC's approach to reviewing the protocols of any transmission owner or generator owner that acts on an Operating Instruction in order to ensure that three-part communication is used appropriately.

Comments

29. All commenters that address this issue maintain that the two revised COM Reliability Standards appropriately identify the entities that issue and/or receive Operating Instructions, and that the two standards should not be expanded to include transmission owners or generator owners.[26] NERC states that the two COM standards are appropriately tailored to apply to those functional entities that operate the Bulk-Power System as described in the NERC Functional Model and, therefore, apply to transmission operators and generator operators rather than transmission owners and generator owners. However, NERC acknowledges that "there are instances in which Transmission Owners or Generator Owners may receive and act on Operating Instructions within areas operated by RTOs or ISOs."[27] NERC asserts that, in these instances, the generator owner or transmission owner is "acting on behalf of a registered Transmission Operator or Generator Operator under delegation as a member of the RTO or ISO."[28] NERC asserts that, if performance of a reliability requirement is not achieved for a delegated task, "the

[26] *See* NERC Comments at 2, 8; EEI/EPSA Comments at 3-4; ISO/RTO Council Comments at 4; ITC Comments at 4-5; Tri-State G&T Comments at 1.

[27] NERC Comments at 8.

[28] *Id.*

relevant Transmission Operator or Generator Operator responsible for compliance with the Reliability Standards is and has been held accountable."[29]

30. NERC provides several examples of the various approaches to assigning compliance responsibility, including a Joint Registration Organization or Coordinated Functional Registration (as used in ERCOT), and assignment of compliance responsibility through operating agreements and manuals (as used in PJM). In both circumstances, NERC and Regional Entity auditors review the relevant documents assigning compliance responsibility "to determine whether there are gaps in performance under the Reliability Standards as a result of the delegation."[30] In addition, NERC states that "the registered entity for a particular function retains responsibility for providing supporting documentation regarding how a task is delegated," and "for providing proof of compliance under the Reliability Standards."[31]

31. EEI/EPSA maintains that generator owners do not receive and act on Operating Instructions, and therefore should not be included as applicable entities under the proposed standards. EEI/EPSA further maintains that transmission owners do not typically receive and act on Operating Instructions, except in regions where the transmission owners have arrangements to do so under specific operating contracts, and,

[29] *Id.*

[30] *Id.* at 10.

[31] *Id.* at 11.

in those cases, act "sol[ely] at the direction of a responsible regional TOP, having broad area responsibilities."[32]

32. Like NERC, ISO/RTO Council acknowledges that transmission owners and generator owners may act on Operating Instructions from an ISO/RTO, at least within some ISO/RTO regions, but states that in those cases the ISOs have market rules and operating procedures in place for communicating Operating Instructions to utilities and other market participants within their footprint. ISO/RTO Council also asserts that ISOs and RTOs do not control the registration of transmission owners and generator owners within their footprint, but that the entity and the relevant Regional Entity "make the final determination on their registration."[33] Finally, ISO/RTO Council suggests that applying the requirements of the proposed COM standards to generator owners and transmission owners "seems to address an administrative concern as opposed to a reliability concern," given that the "core reliability issue at hand is determining whether the RC, BA or TOP command was followed by the relevant recipient," and given that ISOs and RTOs have market rules or tariff provisions in place that require strict adherence by utilities and market participants.[34] ISO/RTO Council also asserts that, if an ISO or RTO issues a command to an entity that is not registered as a transmission operator or generator operator, and there is a three-part communication failure resulting in an enforcement

[32] EEI/EPSA Comments at 3.

[33] ISO/RTO Council Comments at 3.

[34] *Id.*

action, then the NERC Rules of Procedure should be used to hold that entity responsible.[35]

33. ITC asserts that Operating Instructions, as defined by NERC, cannot apply to a generator owner or transmission owner. ITC raises a related question, however, as to whether a transmission operator can issue an Operating Instruction to another transmission operator under the proposed Reliability Standards.[36] ITC seeks confirmation from the Commission that a transmission operator cannot issue such an instruction or directive to another transmission operator, or if no such confirmation is given, ITC asks that the Commission "explain the basis and process under which a Transmission Operator could issue such an Operating Instruction."[37]

34. Idaho Power asserts that COM-002-4 does not apply to generator owners or transmission owners, without further discussion of whether such entities could ever receive and act on Operating Instructions as defined by NERC. Tri-State G&T agrees that generator owners and transmission owners should not be added as applicable entities, as they rarely, if ever receive an Operating Instruction.

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[35] *Id.* at 4 (asserting that the NERC Rules of Procedure, Appendix 4C, Section 5.11 allows for an ISO or RTO to include in an enforcement proceeding an entity that causes or contributes to an alleged violation of a Reliability Standard).

[36] ITC Comments at 5.

[37] *Id.* at 6.

Commission Determination

35. While several commenters have acknowledged that transmission owners and generator owners can receive and act on Operating Instructions in certain regions, we are persuaded that the proposed Reliability Standards need not be expanded to include those entities at this time. In doing so, we are persuaded by the explanation of NERC that "[w]hile the Transmission Operator or Generator Operator may delegate tasks under the proposed Reliability Standards to other member entities within [an RTO or ISO], the Transmission Operator and Generator Operator retain responsibility for compliance with the Requirements in the proposed Reliability Standards."[38] Moreover, we rely on NERC's explanation that NERC and Regional Entity auditors examine contractual arrangements "to ascertain how tasks are delegated and to determine whether there are gaps in performance . . . as a result of the delegation. Responsibility will always rest with the entity registered with NERC as the Transmission Operator."[39] Thus, in the PJM example, if a transmission owner with delegated operating responsibilities fails to use three-part communication as required under COM-002-4, the registered entity that has delegated the operating responsibilities will remain responsible for the violation.

[38] *See also* ISO/RTO Council Comments at 3-4; EEI/EPSA Comments at 3-4 (Commission approved Operating Agreements "contractually bind TOs to act in conformance with TOP obligations").

[39] NERC Comments at 10-11.

36. ITC requests clarification whether or not a transmission operator can issue an Operating Instruction to another transmission operator, pursuant to COM-001-2 and COM-002-4. We find that the issue is beyond the scope of this rulemaking. The two standards at issue in this proceeding relate to requirements for communications capability and communications protocols, and do not address the relative authorities as between functional entities to require another entity to modify its operations in real-time, which is more properly addressed in the TOP and IRO Reliability Standards, including currently effective Reliability Standard TOP-1-1a.[40]

B. Internal Communication Capability

NOPR

37. In the NOPR, the Commission raised the concern that Reliability Standard COM-001-2 does not appear to carry forward an explicit requirement to maintain adequate internal communications capabilities, unlike the existing COM-001 standard, which states that each reliability coordinator, transmission operator, and balancing authority "shall provide adequate and reliable telecommunication facilities for the exchange of

[40] Requirement R1 of TOP-1-1a states that "Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies." The obligation of a functional entity to respond to an Operating Instruction is also expected to be more explicitly addressed in other TOP and IRO standards under development or awaiting Commission approval, including proposed Reliability Standard IRO-001-4, which requires transmission operators, balancing authorities, generator operators, and distribution providers to comply with their Reliability Coordinator's Operating Instructions except under certain described circumstances.

Interconnection and operating information . . . internally."[41] The Commission stated that maintaining adequate internal communications could be critical to reliability, pointing to specific recommendations in the 2003 Blackout Report. The Commission proposed to direct NERC to develop modifications to COM-001-2, or to develop a separate standard, "that ensures that entities maintain adequate internal communications capability, at least to the extent that such communications could involve the issuance or receipt of Operating Instructions or other communications that could have an impact on reliability." [42] Alternatively, the Commission suggested that a requirement for internal communication capability could be considered to be implicit in the proposed requirements for communications capability between functional entities, even if those functional entities reside within the same utility, and sought comment on this suggested interpretation as well as the proposed directive.

Comments

38. NERC and most other commenters assert that Reliability Standard COM-002-4 can and should be read to apply to internal communications between functional entities within the same organization, as the Commission suggested in the NOPR.[43] NERC and NRECA also assert that acceptance of this interpretation should eliminate the need for

[41] NOPR, 148 FERC ¶ 61,210 at P 28 (quoting COM-001-1.1, Requirement R1).

[42] *Id.* P 30.

[43] NERC Comments at 13; *see also, e.g.*, NRECA Comments at 1, Idaho Power Comments at 4, and Tri-State Comments at 1.

further modification to COM-002-4.[44] ITC comments that COM-001-2 should apply to internal communications between different functional entities within the same organization but only "when those communications are performed by means other than in direct, face-to-face situations."[45] ITC continues, stating that "[f]or entities performing multiple functions that are located in close proximity such that direct, face-to-face communication is available, ITC does not see a reliability need for a requirement for Alternative Interpersonal Communication, and believes the Standards should be interpreted as not requiring AIC in these situations."[46] ITC also advocates that, if the Commission does not find that COM-001-2 as submitted includes these kinds of internal communications, the standard ought to be modified to do so.

39. EEI/EPSA acknowledges that the approach taken in COM-001-2 is different than the currently-effective COM standard with respect to internal communications, but maintains that this change is consistent with results-based standards. EEI/EPSA maintains that "a result-based standard should not need to specifically cite facility requirements or the specific internal communication obligations," and maintains that COM-001-2 properly specifies communications capability "at the Functional Entity level."[47]

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[44] NERC Comments at 13; NRECA Comments at 1-2.

[45] ITC Comments at 7.

[46] *Id.*

[47] *Id.* at 4-5.

Commission Determination

40. We agree with NERC and other commenters that Reliability Standard COM-001-2 applies to communications between functional entities within a single organization. For example, COM-001-2, Requirement R3, provides that "each Transmission Operator shall have Interpersonal Communication capability" with the reliability coordinator, and each balancing authority, distribution provider, and generator operator "within its Transmission Operator Area." We agree with NERC, ITC and other commenters that a reasonable understanding of Requirement R3 is that the transmission operator must have Interpersonal Communication capability with a balancing authority, distribution provider and/or generator operator within the same organization. Moreover, we agree with ITC that the COM-001-2 requirements concerning Alternative Interpersonal Communication only apply when those communications are performed by means other than direct, face-to-face situations.

41. However, the application of COM-001-2 to different functional entities within the same organization, as discussed above, does not fully address our concern set forth in the NOPR regarding internal communications.[48] In particular, the NOPR explained that Requirement R1.1 of currently-effective COM-001-1.1 provides that each reliability coordinator, transmission operator, and balancing authority "shall provide adequate and reliable telecommunication facilities for the exchange of Interconnection and operating

[48] *See* NOPR, 148 FERC ¶ 61,210 at PP 28-31.

information . . . internally." This currently-effective Requirement applies more broadly to internal communications, including internal communications *within* the same functional entity. Thus, unlike the currently-effective Reliability Standard, COM-001-2 does not address the adequacy of internal telecommunications (or other internal communication systems) that may have an adverse effect on reliability, even within a single functional entity, including: (1) communications between geographically separate control centers within the same functional entity; and (2) communications between a control center and field personnel. These scenarios present a gap in reliability of the Bulk-Power System that NERC should address. Accordingly, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop modifications to COM-001-2, or to develop a new standard, to address our concerns regarding ensuring the adequacy of internal communications capability whenever internal communications could directly affect the reliable operation of the Bulk-Power System.

C. Testing Requirements for Distribution Providers and Generator Operators

NOPR

42. In the NOPR, the Commission expressed concern that Reliability Standard COM-001-2 did not include a requirement that distribution providers and generator operators test or actively monitor their telecommunications systems, but were merely required to consult with each affected entity to determine a mutually agreeable action for restoration

whenever a failure is detected.[49] The Commission asked for comment on "why generator operators and distribution providers should not have some form of requirement to test or actively monitor vital primary and emergency telecommunication facilities."[50]

Comments

43. NERC and the other commenters on this issue maintain that there is no need for a testing requirement for generator operators and distribution providers comparable to that required for reliability coordinators, balancing authorities and transmission operators, because generator operators and distribution providers are required to maintain only primary Interpersonal Communication capability, which is tested through routine use.[51] NERC further explains that its approach is consistent with the Commission's statement in Order No. 693 that "[w]e expect the telecommunication requirements for all applicable entities will vary according to their roles and that these requirements will be developed under the Reliability Standards development process."[52] NERC also explains that the standard drafting team found that the obligation to detect and address failures in a

[49] NOPR, 148 FERC ¶ 61,210 at P 31 (citing to COM-001-2, Requirement R11).

[50] *Id*, (citing *System Restoration Reliability Standards*, Order No. 749, 134 FERC ¶ 61,215, at P 28 (2011)).

[51] *See, e.g.*, NERC Comments at 14 ("routine use is sufficient to demonstrate functionality of this . . . primary capability"); EEI/EPSA Comments at 5-6 ("a system in regular use would gain little through routine testing"); and ISO/RTO Council Comments at 6-7 ("capability will be 'tested' through regular use").

[52] NERC Comments at 14-15 (quoting Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 487).

primary communication system, as set out in Requirement R11 of COM-001-2, is sufficient, given "the limited impact a failure might have on Distribution Providers and Generator Operators overall."[53]

Commission Determination

44. We are persuaded by the comments of NERC and others that additional testing requirements for distribution providers and generator operators are not necessary at this time. NERC and other commenters assert that the primary Interpersonal Communication systems used by a distribution provider or generator operator will effectively be tested through routine use, and that any potential failures in a given generator operator or distribution provider's external communication system will not have a substantial impact on the Bulk-Power System. In light of this explanation, as well as our recognition in Order No. 693 that telecommunication requirements for applicable entities will vary according to their roles, we decline to require any additional testing requirements for distribution providers and generator operators at this time.

D. Definition of Interpersonal Communication and Alternative Interpersonal Communication

NOPR

45. In the NOPR, the Commission sought clarification on the intended scope of the newly defined terms Interpersonal Communication and Alternative Interpersonal

[53] NERC Comments at 14.

Communication.[54] The Commission noted that NERC had explained the introduction of these terms as a means of eliminating the ambiguity in the terms "adequate and reliable" and "redundant and diversely routed" as currently used in Requirements R1 and R1.4 of COM-001-1.1.

46. The Commission raised two concerns about the new terms as used in proposed Reliability Standard COM-001-2. First, the Commission noted that the definitions do not state a minimum expectation of communication performance, such as speed and quality.[55] Second, the Commission asked for clarification as to whether Interpersonal Communication includes mediums used directly to exchange or transfer data, which communications appear to be covered under the currently-approved version of COM-001.[56] The Commission, thus, asked for further explanation "regarding acceptable (and

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[54] NOPR, 148 FERC ¶ 61,210 at P 32. As previously noted, NERC is proposing to define the terms, respectively, as follows:

> Interpersonal Communication – Any medium that allows two or more individuals to interact, consult, or exchange information.
>
> Alternative Interpersonal Communication – Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.

[55] NOPR, 148 FERC ¶ 61,210 at P 33.

[56] *Id.* As the Commission noted, COM-001-1.1, Requirement R1 addresses "telecommunications facilities for the exchange of Interconnection and operating information."

unacceptable) performance of communication for both Interpersonal and Alternative Interpersonal Communications."[57]

Comments

47. With respect to minimum performance standards or specifications for the required communications mediums, none of the commenters believe such specifications are necessary or advisable. NERC maintains that additional specifications are not necessary because the standard as written requires applicable entities to have the working capability needed to maintain reliability.[58] EEI/EPSA agrees that performance specifications are not necessary, and questions whether it is even possible to set such standards given the diversity of systems used.[59] ISO/RTO Council asserts that it would be inadvisable to include technical specifications on the communication mediums required, as it could result in the use of the least expensive medium that could achieve compliance.[60] Idaho Power suggests that the kinds of measurable characteristics that might be appropriate for use to establish minimum performance levels for data exchanges are not available here, because the proposed COM standards do not include data exchange. Tri-State G&T states that the most common expected mediums for communication under the standard

[57] *Id.*

[58] NERC Comments at 4, 15-16.

[59] EEI/EPSA Comments at 6-7.

[60] ISO/RTO Council at 5. ISO/RTO Council also notes that its members already have requirements in place with their stakeholders on necessary technical requirements for voice and data exchange.

will likely be e-mail and telephone, and that there is no need to include minimum expectations of speed or performance because "all entities are focused on reliability and would always use the fastest and most reliable means of communication."[61]

48. With respect to the transfer of data as opposed to communications between persons, all of the commenters to directly address the issue acknowledge that proposed Reliability Standard COM-001-2 is not intended to, and does not, cover data exchanges or transfers. NERC (through its initial and supplemental comments) and ISO/RTO Council maintain that COM-001-2 need not include requirements regarding data transfer capability because such capability is covered under other existing or proposed standards.

49. With respect to existing standards, NERC states that the standard drafting team determined that IRO-010-1a and IRO-014-1 "provided the necessary mandatory Requirements to ensure proper data exchange is occurring."[62] ISO/RTO Council provides several additional examples of existing Reliability Standards that address data exchange and transfer capability, including BAL-004-2b, R14; IRO-002-2, R1; and TOP-006-2, R1.[63]

50. With respect to standards under development, NERC asserts that four proposed IRO and TOP standards, now approved by the Board, "include specific coverage related

[61] Tri-State G&T Comments at 2.

[62] NERC Comments at 16. *See also* ISO/RTO Council Comments at 5-6 (noting that the standard drafting team explained that data communication is covered under Requirement R3 of IRO-010-1).

[63] ISO/RTO Council Comments at 6, n.10.

to data exchange," and "collectively require data exchange capability" for reliability coordinators, transmission operators, balancing authorities, generator operators, and distribution providers.[64] NERC describes the specific requirements in proposed Reliability Standards TOP-001-3, IRO-010-2, TOP-003-3, and IRO-002-4 that will address data exchange capabilities and/or data exchange specifications for applicable functional entities.

51. EEI/EPSA and Idaho Power also maintain that the term Interpersonal Communication does not cover data exchange, with EEI/EPSA asserting that the phrase requires a system "that enables effective communications between two or more individuals."[65] Moreover, EEI/EPSA understands the term Alternative Interpersonal Communication to require certain entities to have backup communications that do not utilize the same infrastructure.

52. ITC asserts that the definitions of Interpersonal Communication and Alternative Interpersonal Communication "could ostensibly be interpreted to extend the Standard beyond verbal and written communications and Operating Instructions to include the transmission of electronic data between control systems that are monitored/used by

[64] NERC Supp. Comments at 3. NERC identified these same four standards in its Initial Comments, but provides a more detailed discussion of the proposed standards and their status in its Supplemental Comments.

[65] EEI/EPSA at 7. Similarly, Idaho Power states that the term was intended to include voice and electronic messaging between people, and exclude data exchanges, such as SCADA and metering data. Idaho Power Comments at 4-5.

system operators."[66] ITC warns that "[i]f the Commission does indeed intend the scope of the Standards to extend to such electronic data transmission, the requirement for Alternative Interpersonal Communication may not be achievable" because "[i]t may simply not be possible to maintain a second pathway for the transmission of such data, whether by dint of data format, system compatibility, or the feasibility of installing a redundant system."[67] ITC accordingly recommends that if an alternative pathway for data transmission is deemed necessary, then the Commission should retain the language from COM-001-1 which requires "redundant and diversely routed systems."[68]

Commission Determination

53. First, we are satisfied that technical specifications regarding minimum levels of performance for the mediums used to satisfy the requirements of COM-001-2 are not necessary at this time. In doing so, we note NERC's explanation that the requirements in COM-001-2 are "absolute" and that entities must "have the capability in place to 'establish Interpersonal Communication capabilities necessary to maintain reliability.'"[69] Moreover, we are persuaded by the commenters that setting performance criteria for the email and telephonic communications at issue here is both impractical and unnecessary.

[66] ITC Comments at 8.

[67] *Id.*

[68] *Id.* at 9.

[69] NERC Comments at 15-16.

54. Second, the NOPR raised concerns pertaining to whether COM-001-2 addresses "facilities that directly exchange or transfer data." [70] In response, NERC states that data exchange capability is being addressed in proposed IRO and TOP standards.[71] Accordingly, we do not make any determinations regarding data exchange capability in the immediate rulemaking. Rather, based on NERC's explanation, we will address any issues regarding data exchange capability in the pending rulemaking pertaining to NERC's proposed TOP and IRO Reliability Standards.

III. Information Collection Statement

55. The collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[72] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[73] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing

[70] *See* NOPR, 148 FERC ¶ 61,210 at P 33.

[71] *See* NERC Supplemental Filing at 2-3. On March 18, 2015, NERC submitted a petition for approval of proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, Docket No. RM15-15-000, pending before the Commission.

[72] 44 U.S.C. 3507(d) (2012).

[73] 5 CFR 1320.11 (2013).

to respond to these collections of information unless the collections of information display a valid OMB control number.

56. The Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically, the Commission asked that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates were generated.

57. The Final Rule approves Reliability Standards COM-001-2 and COM-002-4, as well as NERC's proposed retirement of currently-effective Reliability Standards COM-001-1.1 and COM-002-2. Reliability Standard COM-001-2 establishes Interpersonal Communication capability necessary to maintain reliability, while Reliability Standard COM-002-4 improves communications related to Operating Instructions, requiring issuers of Operating Instructions to adopt predefined communications protocols and requiring both issuers and recipients of Operating Instructions to use three-part communications.

Public Reporting Burden: Reliability Standards COM-001-2 and COM-002-4 do not require responsible entities to file information with the Commission. However, the Reliability Standards require applicable entities to develop and maintain certain information, subject to audit. In particular, COM-001-2 requires that transmission operators, balancing authorities, reliability coordinators, distribution providers, and

generator operators must maintain documentation of Interpersonal Communication capability and designation of Alternate Interpersonal Communication, as well as evidence of testing of the Alternate Interpersonal Communication facilities. COM-002-4 requires balancing authorities, distribution providers, reliability coordinators, transmission operators, and generator operators to develop and maintain documented communication protocols, and to be able to provide evidence of training on the protocols and of their annual assessment of the protocols. Additionally, all applicable entities (balancing authorities, reliability coordinators, transmission operators, generator operators, and distribution providers) must be able to provide evidence of three-part communication when issuing or receiving an Operating Instruction during an Emergency.

Many of the record retention or information collection requirements in COM-001-2 and COM-002-4 are translated in some form from the currently-effective Reliability Standards (COM-001-1 and COM-002-2). For these requirements, the Commission estimates a zero net change in burden. Accordingly, our estimate below shows the increase in record-retention or information collection burden, based on the new requirements to:

> (1) develop communications protocols (a one-time burden under COM-002-4, Requirement R1),
>
> (2) maintain evidence of required training, assessments, and use of three-part communications, as applicable (an on-going burden under COM-002-4 Requirements R2, R3, R4, R5 and R6); and
>
> (3) maintain evidence to demonstrate Interpersonal Communication capability (a new, on-going burden for distribution providers and generator operators under COM-001-2 Requirements R7 and R8).

The Commission's estimate of the number of respondents is based on the NERC compliance registry as of August 15, 2014. According to the NERC compliance registry, NERC has registered 179 transmission operators, 107 balancing authorities, 15 reliability coordinators, 475 distribution providers, and 853 generator operators within the United States. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting, which has been accounted for in the table below. The Commission estimates the annual reporting burden and cost as follows:

Information Collection Requirement	Number and Type of Respondents (1)	Annual Number of Responses per Respondent (2)	Total Number of Responses (1)*(2)=(3)	Avg. Burden & Cost Per Response[74] (4)	Total Annual Burden Hours & Total Annual Cost[75] (3)*(4)=(5)

[74] The estimated hourly costs (salary plus benefits) are based on Bureau of Labor Statistics (BLS) information, as of March 19, 2015, for an electrical engineer ($65.34/hour for review and documentation) and for an Information and Record Clerk ($33.42/hour for record retention). These figures have been updated since issuance of the NOPR, and are *available at*: http://bls.gov/oes/current/naics3_221000.htm#17-0000. The first row of the table (one-time burden) is done by an engineer, and the latter three rows (ongoing burden) are done by a file clerk.

[75] This dollar burden figure in row 3 of this chart was incorrectly stated in the NOPR, which led to an incorrect estimate of the total dollar burden for the industry in row 5. Both estimates as stated in the NOPR were higher than the corrected and updated estimate reflected in this Final Rule.

(One-time) Development of Communication Protocols [COM-002-4 R1]	212 (BA, RC & TOP)	1	212	8 hrs. & $522.72	1,696 hours & $110,816.64
(On-going) Maintain evidence of Interpersonal Communication capability [COM-001-2 R7 and R8][76]	1,217 (DP & GOP)	1	1,217	4 hrs. & $133.68	4,868 hours & $162,688.56
(On-going) Maintain evidence of training and assessments [COM-002-4 R2, R4, R5 and R6]	212 (BA, RC & TOP)	1	212	8 hrs. & $267.36	1,696 hours & $56,680.32
(On-going) Maintain evidence of training [COM-002-4 R3, and R6]	1,217 (DP & GOP)	1	1,217	8 hrs. & $267.36	9,736 hours & $ 325,377.12
TOTAL			2,858		17,996 hours & $655,562.64

Title: Mandatory Reliability Standards for the Bulk-Power System: COM Reliability Standards.

[76] No change is expected in the record-keeping burden under COM-001-2 for reliability coordinators, balancing authorities, and transmission operators as compared to the currently-effective COM-001 standard.

Action: Proposed FERC-725V

OMB Control No: 1902-0277

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: One-time and ongoing.

Necessity of the Information: The approval of Reliability Standards COM-001-2 and COM-002-4 implements the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the purpose of the Reliability Standards is to establish Interpersonal Communication capability necessary to maintain reliability, and to improve communications for the issuance of Operating Instructions with predefined communications protocols. The proposed Reliability Standards require entities to maintain records subject to review by the Commission and NERC to ensure compliance with the Reliability Standards.

Internal Review: The Commission has reviewed the requirements pertaining to the Reliability Standards for the Bulk-Power System and determined that the requirements are necessary to meet the statutory provisions of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

58. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE,

Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

59. Comments concerning the information collections approved in this Final Rule and the associated burden estimates should be sent to the Commission in these dockets and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference FERC-725V and the docket numbers of this Notice of Proposed Rulemaking (Docket No. RM14-13-000) in your submission.

IV. Regulatory Flexibility Act Certification

60. The Regulatory Flexibility Act of 1980 (RFA)[77] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. Reliability Standard COM-001-2 is expected to impose burdens for the first time on 1,217 entities (i.e., distribution providers and generator operators).[78]

[77] 5 U.S.C. 601-612.

[78] The number of small distribution providers required to comply with the COM standards may decrease significantly. In March 2015, the Commission approved revisions to the NERC Rules of Procedure to implement NERC's "risk based registration" program, which raised the registry threshold for distribution providers from a 25 MW to 75 MW peak load. *North American Electric Reliability Corp.*, 150 FERC ¶ 61,213 (2015).

Reliability Standard COM-002-4 may apply to as many as 1,279 entities.[79] Comparison of the applicable entities with FERC's small business data indicates that approximately 934 of the 1,279 entities are small entities.[80]

61. Reliability Standard COM-002-4 will serve to enhance reliability by, among other things, requiring adoption of predefined communication protocols, annual assessment of those protocols and operating personnel's adherence thereto, training on the protocols, and use of three-part communications. The Commission estimates that each small balancing authority, reliability coordinator, and transmission operator subject to Reliability Standard COM-002-4 will incur one-time compliance costs of about $523 (i.e. development of communication protocols), plus on-going annual costs of about $790 (i.e. performing training and maintaining evidence of training and assessments).[81] The Commission estimates that each of the small distribution provider and generator operator entities potentially subject to Reliability Standards COM-001-2 and COM-002-4 will incur on-going annual costs of about $887 (i.e. performing training and maintaining

[79] The applicable entities are balancing authorities, reliability coordinators, transmission operators, generator operators, and distribution providers. After accounting for entities registered for more than one function, the total count is 1,279 entities.

[80] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. The possible categories for the applicable entities have a size threshold ranging from 250 employees to 1,000 employees. We are using the 1000 employee threshold for this analysis.

[81] The ongoing annual costs for both paperwork and training are based on (8 hours * $33.42) + (8 * $65.34) = $790.16 or approximately $790.00.

evidence of interpersonal communication capability and of training).[82] The Commission does not consider the estimated costs per small entity to have a significant economic impact on a substantial number of small entities. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

V. Environmental Analysis

62. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[83] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[84] The actions approved herein fall within this categorical exclusion in the Commission's regulations.

VI. Document Availability

63. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page

[82] The ongoing annual cost is based on (12 * $33.42) + (8 * $60.70) = $886.64 or approximately $887.00.

[83] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[84] 18 CFR 380.4(a)(2)(ii).

(http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

64. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

65. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

66. This Final Rule is effective **[insert date 60 days from publication in the Federal Register].**

67. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of

1996.[85] The Commission will submit the Final Rule to both houses of Congress and to the General Accountability Office.

68. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[85] *See* 5 U.S.C. 804(2).

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004 _in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			
33	Project 2006-07	ATC et al Standard - MOD-004 _rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			
34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
35	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 93.04% Approval: 57.37%			
36	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 87.62% Approval: 97.47%			
37	Project 2006-01	Project 2006-01 - PER-005-1_rc	Recirculation Ballot	12/12/2008	12/22/2008	Quorum: 91.48% Approval: 80.63%			
38	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.15% Approval: 97.39%			
39	Project 2008-16	TOP-004-2 VSL Revisions_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.20% Approval: 93.93%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_rc	Recirculation Ballot	1/6/2009	1/15/2009	Quorum: 91.47% Approval: 91.21%			
41	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_rc	Recirculation Ballot	1/20/2009	1/29/2009	Quorum: 85.86% Approval: 86.39%			
42	Project 2008-16	TOP-004-2 VSL Revisions_rc	Recirculation Ballot	1/28/2009	2/6/2009	Quorum: 92.59% Approval: 96.06%			
43	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_rc	Recirculation Ballot	2/6/2009	2/16/2009	Quorum: 93.81% Approval: 99.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - R1 - RECM_in	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.67% Approval: 89.03%			
45	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_in	Initial Ballot	3/19/2009	3/30/2009	Quorum: 89.78% Approval: 92.62%			
46	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_in	Initial Ballot	4/1/2009	4/10/2009	Quorum: 91.90% Approval: 84.06%			
47	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_in	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.70% Approval: 92.71%			
48	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_in	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 94.37% Approval: 88.32%			
50	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 95.56% Approval: 92.81%			
51	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_in	Initial Ballot	4/22/2009	5/1/2009	Quorum: 88.64% Approval: 84.77%			
52	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_rc	Recirculation Ballot	5/6/2009	5/18/2009	Quorum: 92.08% Approval: 75.39%			
53	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_in	Initial Ballot	5/25/2009	6/4/2009	Quorum: 85.13% Approval: 82.10%			
54	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_rc	Recirculation Ballot	5/26/2009	6/5/2009	Quorum: 90.45% Approval: 85.76%			
55	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_in	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.10% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_in	Initial Ballot	6/12/2009	6/22/2009	Quorum: 81.72% Approval: 94.09%			
57	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_in	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 83.94%			
58	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_rc	Recirculation Ballot	7/7/2009	7/16/2009	Quorum: 92.77% Approval: 84.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_rc	Recirculation Ballot	7/8/2009	7/17/2009	Quorum: 90.26% Approval: 82.25%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_rc	Recirculation Ballot	7/10/2009	7/20/2009	Quorum: 87.10% Approval: 96.94%			
61	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 95.26% Approval: 95.62%			
62	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 91.24% Approval: 98.85%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 90.46%			
64	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.40% Approval: 89.14%			
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 88.26%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.16% Approval: 90.15%			
67	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.63%			
68	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.64% Approval: 87.63%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
69	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.50% Approval: 85.78%			
70	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.28% Approval: 89.56%			
71	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.98% Approval: 87.31%			
72	Project 2009-17	Project 2009-17 Interpretation - Y-W Electric and Tri-State - PRC-004-1 and PRC-005-1_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 90.32% Approval: 62.15%			
73	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rb	Re-ballot	7/27/2009	8/14/2009	Quorum: 84.65% Approval: 74.79%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_in	Initial Ballot	8/6/2009	8/17/2009	Quorum: 84.68% Approval: 68.92%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 89.28%			
76	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.04% Approval: 89.41%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.41% Approval: 84.64%			
78	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.17% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 90.77%			
81	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.31% Approval: 86.93%			
82	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.11% Approval: 88.26%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.70% Approval: 85.80%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan_in	Initial Ballot	8/19/2009	8/28/2009	Quorum: 81.96% Approval: 97.37%			
85	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rc	Recirculation Ballot	8/20/2009	8/31/2009	Quorum: 86.96% Approval: 70.85%			
86	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.68% Approval: 80.37%			
87	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.92% Approval: 79.04%			
88	Project 2009-18	Project 2009-18 - Withdraw Three Midwest ISO Waivers_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 85.28% Approval: 99.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan_rc	Recirculation Ballot	9/1/2009	9/10/2009	Quorum: 87.11% Approval: 97.18%			
90	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rc	Recirculation Ballot	9/2/2009	9/14/2009	Quorum: 86.31% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_in	Initial Ballot	9/10/2009	9/21/2009	Quorum: 87.45% Approval: 94.18%			
92	Project 2009-16	Project 2009-16 - Interpretation - WECC - CIP-007-1_in	Initial Ballot	9/9/2009	9/21/2009	Quorum: 85.31% Approval: 100.00%			
93	Project 2006-04	Project 2006-04 - Back-up Facilities - EOP-008-1_in	Initial Ballot	9/16/2009	9/28/2009	Quorum: 82.69% Approval: 72.86%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_rc	Recirculation Ballot	9/29/2009	10/9/2009	Quorum: 89.92% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 Revised R1 for Progress Energy	Initial Ballot	9/30/2009	10/12/2009	Quorum: 79.92% Approval: 74.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_rc	Recirculation Ballot	10/16/2009	10/26/2009	Quorum: 86.29% Approval: 83.25%			
97	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_rc	Recirculation Ballot	11/2/2009	11/12/2009	Quorum: 88.70% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 2_in	Initial Ballot	11/5/2009	11/16/2009	Quorum: 85.97% Approval: 98.07%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_in	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.58% Approval: 88.07%			
100	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 1)_in	Initial Ballot	11/19/2009	12/7/2009	Quorum: 85.83% Approval: 58.91%			
101	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._in	Initial Ballot	11/20/2009	12/7/2009	Quorum: 87.11% Approval: 93.40%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_rc	Recirculation Ballot	12/3/2009	12/14/2009	Quorum: 93.33% Approval: 85.55%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
103	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers_in	Initial Ballot	12/1/2009	12/14/2009	Quorum: 86.13% Approval: 72.11%			
104	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_rc	Recirculation Ballot	12/11/2009	12/23/2009	Quorum: 90.08% Approval: 78.77%			
105	Project 2009-24	Project 2009-24 - Interpretation - FMPA - EOP-005-1_ in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 87.68% Approval: 17.79%			
106	Project 2009-25	Project 2009-25 - Interpretation - BPA - BAL-001-01.a and BAL-002-0_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 88.00% Approval: 34.28%			
107	Project 2009-26	Project 2009-26 - Interpretation - WECC - CIP-004-1_in	Initial Ballot	1/6/2010	1/19/2010	Quorum: 84.21% Approval: 42.24%			
108	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Initial Ballot	1/12/2010	1/22/2010	Quorum: 89.16% Approval: 75.16%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP_in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP_in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP_rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1)_in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions_in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions_rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order_in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
137	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_rc	Recirculation Ballot	8/20/2010	8/30/2010	Quorum: 88.26% Approval: 93.93%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Initial Ballot	9/14/2010	9/24/2010	Quorum: 92.73% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Initial Ballot	9/17/2010	9/27/2010	Quorum: 96.46% Approval: 21.77%			
140	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	9/24/2010	10/4/2010	Quorum: 85.71% Approval: 81.72%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	10/2/2010	10/14/2010	Quorum: 84.11% Approval: 84.52%			
142	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_rc	Recirculation Ballot	10/4/2010	10/14/2010	Quorum: 88.11% Approval: 99.14%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc	Recirculation Ballot	10/5/2010	10/15/2010	Quorum: 92.19% Approval: 94.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_rc	Recirculation Ballot	10/6/2010	10/16/2010	Quorum: 91.21% Approval: 93.44%			
145	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Recirculation Ballot	10/18/2010	10/28/2010	Quorum: 89.84% Approval: 84.67%			
146	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 93.66% Approval: 43.33%			
147	Project 2010-10	Project 2010-10 FAC-013-2 Planning Transfer Capability_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 88.54% Approval: 39.85%			
148	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_in	Initial Ballot	10/28/2010	11/7/2010	Quorum: 81.61% Approval: 93.72%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Recirculation Ballot	11/1/2010	11/11/2010	Quorum: 89.41% Approval: 86.83%			
150	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_rc	Recirculation Ballot	11/9/2010	11/13/2010	Quorum: 87.00% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_rc	Recirculation Ballot	11/19/2010	12/3/2010	Quorum: 87.81% Approval: 82.41%			
152	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_in	Initial Ballot	12/1/2010	12/10/2010	Quorum: 87.07% Approval: 77.06%			
153	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-3	Initial Ballot	12/2/2010	12/11/2010	Quorum: 84.46% Approval: 42.89%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Recirculation Ballot	12/2/2010	12/13/2010	Quorum: 95.50% Approval: 86.91%			
155	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Initial Ballot	12/7/2010	12/16/2010	Quorum: 88.00% Approval: 51.51%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Successive Ballot	12/10/2010	12/20/2010	Quorum: 79.88% Approval: 44.65%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	12/10/2010	12/20/2010	Quorum: 78.00% Approval: 53.00%			
158	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_rc	Recirculation Ballot	12/20/2010	12/30/2010	Quorum: 90.49% Approval: 80.56%			
159	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_in	Recirculation Ballot	12/27/2010	1/5/2011	Quorum: 90.42% Approval: 83.33%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 22.09%	Oppose 12/16/11		
161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 33.49%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 26.82%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 28.04%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.60%	Oppose 12/16/11		
165	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 24.15%	Oppose 12/16/11		
166	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 94.02% Approval: 34.30%	Oppose 12/16/11		
167	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 27.28%	Oppose 12/16/11		
168	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 26.61%	Oppose 12/16/11		
169	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.88%	Oppose 12/16/11		
170	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.15% Approval: 42.06%	Oppose 12/16/11		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
171	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.56% Approval: 25.34%	Oppose 12/16/11		
172	Project 2010-10	Project 2010-10: FAC Order 729_in	Initial Ballot	12/30/2010	1/8/2011	Quorum: 83.23% Approval: 58.16%			
173	Project 2010-10	Project 2010-10: FAC Order 729_rc	Recirculation Ballot	1/14/2011	1/23/2011	Quorum: 86.65% Approval: 68.98%			
174	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_rc	Recirculation Ballot	1/26/2011	2/5/2011	Quorum: 93.29% Approval: 86.79%	Support 1/5/11		
175	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot	1/24/2011	2/14/2011	Quorum: 83.95% Approval: 65.71%	Support 2/11/11		
176	Project 2007-23	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/2011	2/22/2011	Quorum: 78.00% Approval: 72.00%	Support 10/28/10		
177	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Successive Ballot	2/18/2011	2/28/2011	Quorum: 79.28% Approval: 79.34%	Support 2/22/11		
178	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/2011	3/6/2011	Quorum: 87.35% Approval: 68.83%	Support 2/11/11		
179	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/2011	3/7/2011	Quorum: 87.10% Approval: 49.54%	Support 3/2/11		
180	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-4	Successive Ballot	4/19/2011	4/28/2011	Quorum: 79.66% Approval: 38.00%	Oppose 4/19/11		
181	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Initial Ballot	4/21/2011	5/2/2011	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11		
182	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Non-binding Poll	4/21/2011	5/2/2011	Quorum: 75.58% Approval: 73.00%			
183	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Successive Ballot	5/3/2011	5/12/2011	Quorum: 78.33% Approval: 67.00%	No Recommendation		
184	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	5/3/2011	5/12/2011	Quorum: 75.00% Approval: 66.00%			
185	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Recirculation Ballot	5/12/2011	5/23/2011	Quorum: 91.25% Approval: 78.92%	Support 5/12/11		
186	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot	5/18/2011	5/31/2011	Quorum: 92.07% Approval: 73.99%			
187	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Non-binding Poll	5/18/2011	5/31/2011	Quorum: 86.79% Approval: 71.9%			
188	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Initial Ballot	5/31/2011	6/9/2011	Quorum: 88.47% Approval: 48.64%	Oppose 5/31/11		
189	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Non-binding Poll	5/31/2011	6/9/2011	Quorum: 84.18% Approval: 41.00%			
190	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot	6/20/2011	6/30/2011	Quorum: 82.97% Approval: 64.76%	Support 6/28/11		
191	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Non-binding Poll	6/20/2011	6/30/2011	Quorum: 52.63% Approval: 60.00%			
192	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	Recirculation Ballot	7/13/2011	7/22/2011	Quorum: 94.33% Approval: 75.37%			
193	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.99%	Support 7/22/11		
194	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 75.17%	Support 7/22/11		
195	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.27%	Support 7/22/11		
196	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 93.00%			
197	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.66% Approval: 93.00%			
198	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 89.00%			
199	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11		
200	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.75% Approval: 56.00%			
201	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11		
202	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.35% Approval: 20.79%			
203	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Initial Ballot	9/19/2011	9/29/2011	Quorum: 84.86% Approval: 61.10%	Support 9/21/11		
204	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	9/19/2011	9/29/2011	Quorum: 83.13% Approval: 68.68%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
205	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Definition of BES	Initial Ballot	9/30/2011	10/10/2011	Quorum: 92.97% Approval: 71.68%	No Consensus 10/3/11		
206	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Initial Ballot	9/30/2011	10/10/2011	Quorum: 89.53% Approval: 64.03%	No Consensus 10/7/111		
207	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Recirculation Ballot	10/4/2011	10/13/2011	Quorum: 87.17% Approval: 86.25%	Support 2/22/11		
208	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/2011	11/16/2011	Quorum: 88.05% Approval: 85.53%	Support 11/8/11		
209	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Initial Ballot	11/8/2011	11/17/2011	Quorum: 91.20% Approval: 95.05%	Support 11/8/11		
210	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 88.22% Approval: 86.94%	Support 11/10/11		
211	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Initial Ballot	11/9/2011	11/18/2011	Quorum: 85.08% Approval: 85.71%	Support 11/10/11		
212	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.82% Approval: 85.31%	Support 11/10/11		
213	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.29% Approval: 96.09%	Support 11/10/11		
214	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Successive Ballot	11/11/2011	11/21/2011	Quorum: 83.53% Approval: 95.99%	Support 11/14/11		
215	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System and Implementation Plan	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 95.92% Approval: 81.32%	Support 10/3/11		
216	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 93.02% Approval: 81.48%	Support 10/3/11		
217	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Initial Ballot	11/30/2011	12/9/2011	Quorum: 93.92% Approval: 30.82%	Oppose 12/5/11		
218	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Non-binding Poll	11/30/2011	12/9/2011	Quorum: 89.49% Approval: 36.00%			
219	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Initial Ballot	12/2/2011	12/12/2011	Quorum: 87.97% Approval: 36.21%	Oppose 12/5/11		
220	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	12/2/2011	12/12/2011	Quorum: 85.28% Approval: 45.00%			
221	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Recirculation Ballot	12/9/2011	12/19/2011	Quorum: 88.02% Approval: 96.04%	Support 11/14/11		
222	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Recirculation Ballot	12/12/2011	12/22/2011	Quorum: 90.10% Approval: 92.49%	Support 11/8/11		
223	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 92.00% Approval: 94.58%	Support 11/8/11		
224	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 88.48% Approval: 90.10%	Support 11/10/11		
225	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 87.17% Approval: 85.38%	Support 11/10/11		
226	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.91% Approval: 85.03%	Support 11/10/11		
227	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1a	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.65% Approval: 96.43%	Support 11/10/11		
228	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 59.93%	Oppose 1/9/12		
229	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 77.08 %	Support 1/9/12		
230	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 78.95%	Support 1/9/12		
231	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Non-binding Poll	1/4/2012	1/13/2012	Quorum: 78.27% Approval: 93.00%			
232	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Non-binding Poll	1/9/2012	1/18/2012	Quorum: 76.41% Approval: 71.42%			
233	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 67.61%			
234	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 70.28%			
235	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 54.64%	Oppose 2/7/12		
236	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 82.11% Approval: 80.62%	Support 2/7/12		
237	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 80.21%	Support 2/7/12		
238	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.35% Approval: 71.35%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
239	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.06% Approval: 90.86%			
240	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 79.77% Approval: 84.69%			
241	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Successive Ballot	3/14/2012	3/23/2012	Quorum: 88.55% Approval: 79.61%	Support 3/16/12		
242	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Initial Ballot	3/14/2012	3/23/2012	Quorum: 89.63% Approval: 94.71%	Support 3/16/12		
243	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	Initial Ballot	3/14/2012	3/23/2012	Quorum: 86.92% Approval: 63.09%	Support 3/16/12		
244	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 81.45% Approval: 61.21%			
245	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 80.38% Approval: 41.09%			
246	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	3/19/2012	3/29/2012	Quorum: 84.32% Approval: 73.93%	Support 3/19/12		
247	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	3/19/2012	3/29/2012	Quorum: 81.93% Approval: 66.12%			
248	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.37% Approval: 85.18%	Support 4/5/12		
249	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.10% Approval: 85.01%	Support 4/5/12		
250	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.28% Approval: 41.09%	Oppose 4/16/12		
251	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 36.84%	Oppose 4/16/12		
252	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 48.70%%	Oppose 4/16/12		
253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
273	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.98% Approval: 55.08%	Abstain 5/17/12		
274	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.22% Approval: 38.50%	Abstain 5/17/12		
275	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 45.78%	Abstain 5/17/12		
276	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.19% Approval: 67.19%	Abstain 5/17/12		
277	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 60.19%	Abstain 5/17/12		
278	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 47.92%	Abstain 5/17/12		
279	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 58.23%	Abstain 5/17/12		
280	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	5/11/2012	5/21/2012	Quorum: 85.12% Approval: 66.23%	Abstain 5/17/12		
281	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	5/11/2012	5/21/2012	Quorum: 84.09% Approval: 47.88%	Abstain 5/17/12		
282	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	5/15/2012	5/24/2012	Quorum: 84.43% Approval: 46.18%			
283	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	5/15/2012	5/24/2012	Quorum: 79.95% Approval: 52.67%			
284	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Initial Ballot	6/11/2012	6/20/2012	Quorum: 84.14% Approval: 21.11%	Oppose 6/13/12		
285	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	6/11/2012	6/20/2012	Quorum: 81.01% Approval: 28.30%			
286	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	6/18/2012	6/27/2012	Quorum: 79.46% Approval: 79.00%			
287	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	6/18/2012	6/27/2012	Quorum: 75.00% Approval: 70.21%			
288	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/2012	6/27/2012	Quorum: 85.98% Approval: 68.22%	Support 6/26/12		
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			
331	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
364	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012 in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		

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375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013 in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		
386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard- NPCC will submit suggested improvements
390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			

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399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	

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453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative		
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative		
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative		
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative		
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative		
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative		
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative		
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative		
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14	
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative		
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative		
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative		
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative		
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative		
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14	
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative		
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative		
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--		
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain		
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative		
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR 002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative		
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	[illegible]	Affirmative Negative Affirmative Affirmative	
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative	
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29% Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14		
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative	
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative	
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative	
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative	
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing -	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91% Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		

RSC Meeting #14-2, Agenda Item 6.3: Comment History

(Since last RSC Meeting)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11

RSC Meeting #14-2, Agenda Item 6.3: Comment History

(Since last RSC Meeting)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
25.	N/A	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CAN-0024 CIP-002 through CIP-009		5/20/11	6/10/11	

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26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	
29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
35..	N/A	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	CAN-0016 CIP-001, R1		8/15/11	9/6/11	Yes 9/6/11
36.	N/A	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004	CAN-0001 through 0004 Retirement		8/31/11	9/21/11	

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37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11
40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
45.	N/A	CAN-0011--PRC-005-1 R2: New Equipment	CAN-0011 PRC-005-1 R2		10/10/11	10/31/11	Yes 10/31/11
46.	N/A	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN-0012 Completion of Periodic Activity Requirements		10/10/11	10/31/11	Yes 10/31/11
47	N/A	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN-0013 PRC-023 R1 and R2		10/10/11	10/31/11	
48.	N/A	CAN-0015--Unavailability of NERC Software Tools	CAN-0015 NERC Tools		10/10/11	10/31/11	Yes 10/31/11

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49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	
53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
57.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		10/5/11	11/18/11	Yes 11/18/11
58.	N/A	Draft Directive Regarding Generator Transmission Leads	Draft Directive #2011 CAG-001		10/17/11	11/18/11	Yes 11/18/11
59.	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Interpretation of CIP-006-1, R1.1		10/12/11	11/21/11	Yes 11/21/11
60.	N/A	CAN-0040 - BAL-003 Frequency Bias Calculation			11/2/11	11/23/11	
61.	N/A	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	PRC-005 Evidence		11/2/11	11/23/11	Yes 11/22/11
62.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1			12/8/11	Yes 12/8/11
63.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2			12/12/11	Yes 12/12/11

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64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	
66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	

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74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12
77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12
78.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		2/8/12	3/23/12	Yes 3/23/12
79.	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing - PRC-005	PRC-005-2		2/28/12	3/28/12	Yes 3/28/12
80.	Project 2007-09	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		2/29/12	3/29/12	Yes 3/29/12
81.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	FAC-003-X FAC-003-3		3/9/12	4/9/12	Yes 4/9/12
82.	Project 2007-09	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		2/29/12	4/16/12	Yes 4/16/12
83.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	PRC-005-1.1a		3/2/12	4/16/12	Yes 4/16/12
84.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations	TOP-001 through TOP-008 and PER-001		3/22/12	4/20/12	Yes 4/20/12
85.	Project 2012-INT-02	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		4/24/12	5/4/12	

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86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12
			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12
88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR - 002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12

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96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12
97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12
99.	N/A	Standard Processes Manual Revisions to Implement SPIG Recommendations	SPIG Reco		6/20/12	7/19/12	Yes 7/19/12
100.	Project 2012-INT-02	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	- Interpretation of TPL-003-0a and TPL-004-0		6/20/12	7/20/12	Yes 7/19/12
101.	Project 2012-INT-05	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		6/27/12	7/27/12	Yes 7/27/12
102.	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Rapid Revision to VAR-002		7/18/12	7/27/12	Yes 7/26/12
103.	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Rapid Revision of TOP-006		6/14/12	7/30/12	Yes 7/27/12
104.	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Glossary of Terms		6/19/12	8/2/12	Yes 8/2/12
105.	N/A	Reliability Guideline: System Operator Verbal Communications – Current Industry Practices	System Operator Verbal Communications		6/26/12	8/10/12	Yes 8/9/12
106.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		7/27/12	8/27/12	Yes 8/27/12

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107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	
110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12
112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	

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121.	Project 2013-01	Project 2013-01 - Cold Weather Preparedness			9/25/12	10/24/12	
122.	Project 2007-09	Project 2007-09 - Generator Verification			9/28/12	10/29/12	
123.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System			10/4/12	11/5/12	
124.	2007-12	Project 2007-12 - Frequency Response			10/5/12	11/7/12	
125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	
127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13

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138.	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	PRC-024-1		12/12/12	1/11/13	Yes 1/11/13
139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13
143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13

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163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
175	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	BAL-002-2	Formal	8/2/13	9/16/13	Yes 9/16/13

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176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13
181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
188	Project 2009-03	Project 2009-03 Emergency Operations	SAR	Informal	11/06/13	12/05/13	Yes 12/5/13
189	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002-2	Formal	10/28/13	12/11/13	Yes 12/11/13
190	Project 2007-11	Project 2007-11 - Disturbance Monitoring	PRC-002-2	Formal	11/01/13	12/16/13	Yes 12/16/13

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191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14
199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14

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206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14
213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14

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221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14
225	Project 2015-2017	Project 2015-2017 Reliability Standard Development Plan		Informal		7/21/14	Yes 7/21/14
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14

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		BAL-006					
231	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Formal	07/2/14	08/15/14	Yes 8/13/14
232	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-004-2.1a(X) PRC-004-3(X)	Formal	07/10/14	08/26/14	Yes 8/25/14
233	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X	PRC-005-X	Formal	07/30/14	09/12/14	Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	08/6/14	09/19/14	Yes 9/22/14
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14
236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X CIP-007-X	Formal	09/03/14	10/17/14	Yes 10/17/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			CIP-010-X CIP-011-X				
243	Project 2009-03	Project 2009-03 Emergency Operations	EOP-011-1	Formal	09/05/14	10/20/14	Yes 10/20/14
244	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Preliminary Draft 5)	PRC-027-1	Informal	10/01/14	10/21/14	Yes 10/21/14
245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability for Dispersed Generation Resources	PRC-001-1.1 PRC-019-2 PRC-024-1	Formal	11/05/14	12/23/14	Yes 12/22/14
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-	Project 2014-01	PRC-005-5	Informal	12/22/14	1/20/15	Yes

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	01	Standards Applicability for Dispersed Generation Resources					1/22/15
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15
265	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-008-1	Informal	3/27/15	5/11/15	Yes 5/11/15
266	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-006-2	Informal	3/27/15	5/11/15	Yes 5/11/15
267	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15
269	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)	PRC-027-1	Formal	4/1/15	5/15/15	Yes 5/15/15
270	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15

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		Directives					
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
LOCATIONS FOR DATA CAPTURE (SER, FR) R1. Each Transmission Owner shall: 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data. 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.	**LOCATIONS FOR DATA CAPTURE (SOE, FR)** R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of	**LOCATIONS FOR DATA CAPTURE (SOE, FR)** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance activities do not interfere with DDR requirements.	• The bus identification methodology in PRC-002-2 R1 would probably not include all the buses identified using A-10 thereby making the locations for sequence of events recording in PRC-002-NPCC-01 more stringent. However, the Implementation Plan for PRC-002-NPCC-01 calls for 100 per cent implementation by October, 2015. PRC-002-2 R2 adequately covers changes made to the system beyond that date that would require added sequence of recording data collection. PRC-002-2 stipulates that there is adequate fault recording data to **determine** electrical quantities, which allows for the determination of electrical quantities at buses in addition to the PRC-002-NPCC-01 identified buses. • PRC-002-2 is more stringent in that it requires notification of other BES Element owners (Part 1.2). • PRC-002-2 Part 1.3 is more stringent in that it requires a five calendar year re-evaluation period. • A-15 Sections 3.2 and 3.3 dictate what sequence of events recording data must be captured.	

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
	peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas.	- Bus voltages		

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
SER R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses.	**SER** R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive	**SER** 3.3. Sequence of Events recording shall monitor the following at each location: - Transmission and Generator circuit breaker positions - **Protective Relay** tripping for all **protection groups** - **Teleprotection** keying & receive	• For sequence of events recording PRC-002-NPCC-01 is more stringent. However, the Implementation Plan for PRC-002-NPCC-01 calls for 100 per cent implementation by October, 2015. PRC-002-2 would adequately cover changes made to the system beyond that date. It is preferable to have sequence of events recording equipment, but sequence of events can be determined (monitored) from fault recording data, and target data (as called for in PRC-002-NPCC-01 Part 1.2, A-15 Section 3.3).	

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
FAULT RECORDING R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: 3.1 Phase-to-neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: 4.1 A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. 4.2 A minimum recording rate of 16 samples per cycle. 4.3 Trigger settings for at least the following: 4.3.1 Neutral (residual) overcurrent. 4.3.2 Phase undervoltage or overcurrent.	**FAULT RECORDING** **R2.** Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R3.** Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. **R4.** Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. **R5.** Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: **5.1** Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) **5.2** Three phase currents and neutral currents. **5.3** Polarizing currents and voltages, if used. **5.4** Frequency. **5.5** Real and reactive power. **R6.** Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: **6.1** Each Fault recorder record duration shall be a minimum of one (1) second. **6.2** Each Fault recorder shall have a minimum recording rate of 16 samples per cycle **6.3** Each Fault recorder shall be set to trigger for at least the following: **6.3.1** Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups. **6.3.2** Neutral (residual) overcurrent set at 0.2 pu or	**FAULT RECORDING** 4.1 **Fault** recording is the responsibility of transmission owners and **generation** owners. When adding or replacing a DFR at an existing BPS facility, the TO or GO should complete a notification in accordance with Document C-22. 4.2 **Fault** recording shall be provided by the TO to determine the current zero time for loss of **BPS** transmission **elements**. The current zero time shall be reported as the time of the final current zero on the last phase to interrupt. 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 4.5 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) - Three phase currents and neutral currents. - Polarizing currents and voltages, if used. - Frequency. - Active and reactive power. 4.6 **Fault** recorder record duration shall be a minimum of one (1) second. 4.7 **Fault** recorder minimum recording rate shall be 16 samples per cycle. 4.8 As a minimum, **fault** recorders shall be set to trigger for all the following functions: - **Protective Relay** tripping for all **protection**	Current Zero Time--The time of the final current zero on the last phase to interrupt (from the NERC Glossary--NPCC Section). • The inclusion of “to determine” in PRC-002-2 R3 covers the Elements to be covered in PRC-002-NPCC-01 R2, R3. • For PRC-002-NPCC-01 R4 the Current Zero Time can be determined from the retrieved data. • The quantities specified in PRC-002-NPCC-01 R5 can be determined from the data specified to be retrieved in PRC-002-2 R3. • PRC-002-NPCC-01 R6 is more stringent in that it specifies the record duration, and triggering specifics. However, this is addressed by A-15.	

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
	less of rated CT secondary current. **6.3.3** Monitored phase undervoltage set at 0.85 pu or greater. **6.4** Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.	**groups** - Neutral (residual) overcurrent set at 0.2 pu rated CT secondary current - Phase undervoltage set at 0.85 pu 4.9 When local conditions require different settings or additional functions, such situations shall be documented.		

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
DYNAMIC DISTURBANCE RECORDING R5. Each Responsible Entity shall: 5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: 5.1.1 Generating resource(s) with: 5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA. 5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA. 5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). 5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. 5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL). 5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. 5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element; and 5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. 5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. 5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the	**DYNAMIC DISTURBANCE RECORDING** **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas. **R8.** Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. **R9.** Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: **9.1** A minimum recording time of sixty (60) seconds per trigger event. **9.2** A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second. **9.3** Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities): **9.3.1** Rate of change of Frequency. **9.3.2** Rate of change of Power. **9.3.3** Delta Frequency (recommend 20 mHz change). **9.3.4** Oscillation of Frequency. **R10.** Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: **10.1** Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality. **10.2** Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality. **10.3** As a minimum, one phase current per	**DYNAMIC DISTURBANCE RECORDING** 5.1 Where the DDR capability is deemed necessary by the Reliability Coordinator, the Reliability Coordinator shall provide guidance in setting triggers and shall monitor the performance of the DDR devices. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance activities do not interfere with DDR requirements. - Bus voltages 5.5 As a minimum, DDRs shall monitor one phase current per monitored **element** and two phase-to-neutral voltages of different **elements**. One of the monitored voltages shall be of the same phase as the monitored current. 5.6 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Voltage, current, and frequency - Active and reactive power 5.7 DDRs installed after January 1, 2009 shall function as continuous recorders.	• The inclusion of "to determine" in PRC-002-2 R6, R7 encompasses the data for the facilities/locations in PRC-002-NPCC-01 R7. • PRC-002-2 R8 addresses continuous recorders (PRC-002-NPCC-01 R8). • PRC-002-2 is more stringent in that for triggered DDR, the triggered record lengths must be at least three minutes (Part 8.1). PRC-002-NPCC-01 specifies "A minimum recording time of sixty (60) seconds per trigger event (Part 9.1). • Both PRC-002-2 and PRC-002-NPCC-01 require continuous recording (A-15 specifies this in its 5.7) negating the need for the additional triggering in PRC-002-NPCC-01 Part 9.3. The Implementation Plan for PRC-002-NPCC-01 calls for 100 per cent implementation by October, 2015. • PRC-002-2 is more stringent in that it requires a five calendar year re-evaluation period (Part 5.4). • PRC-002-2 addresses the quantities to be covered in R6 and R7 (PRC-002-NPCC-01 R10). • The timetable for the acquisition of DDR data is listed in PRC-002-2's Implementation Plan. This is more specific/stringent than PRC-002-NPCC-01 R13. • PRC-002-2 addresses "what" data is captured", not "how" it is captured. This covers the "products" of recording equipment. The requirements in PRC-002-2 pertaining to DDR (R5-R9) are performance-based in accordance with the 6/26/13 NERC Standard Processes Manual (page 6).	• PRC-002-NPCC-01 R11 requires documentation of settings to be reported to the RE.

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
re-evaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: 7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level. 7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: 8.1 Triggered record lengths of at least three minutes. 8.2 At least one of the following three triggers:	monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current. **10.4** Frequency. **10.5** Real and reactive power. **R11.** Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. **R12.** Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. **R13.** Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule.	5.8 Each device shall sample data at a rate of at least 960 samples per second (16 samples per cycle and shall store the RMS value of electrical quantities at a rate of at least 6 data points per second.) 5.9 The following DDR triggers shall be considered where available based on manufacturers capability: - Rate of change of Frequency - Rate of change of Power - Delta Frequency 20 mHz change - Oscillation of Frequency 5.10 When local conditions require different settings or additional functions, such situations shall be documented. 5.11 When DDR triggers are used, duration of triggered records shall be a minimum of sixty (60) seconds.		

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
• Off nominal frequency trigger set at: Low High o Eastern Interconnection <59.75Hz >61.0Hz o Western Interconnection <59.55Hz >61.0Hz o ERCOT Interconnection <59.35Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55Hz >61.5Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec >0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec >0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec >0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec >0.1875 Hz/sec • Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds. R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.				

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
TIME SYNCHRONIZATION R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: 10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset. 10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.	**TIME SYNCHRONIZATION** **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**TIME SYNCHRONIZATION** **7.0 Time Synchronization** Internal clocks in DME devices shall be time synchronized to within 2 milliseconds or less of Coordinated Universal Time (UTC) scale. The time zone shall be clearly identified as either universal time zone or local time zone.	• PRC-002-2 R10 is more stringent than PRC-002-NPCC-01 Part 14.4 in its time synchronization specification. A-15 Section 7.0 is consistent with PRC-002-2. • PRC-002-2 addresses “what” data is captured”, not “how” it is captured. This covers the “products” of recording equipment, eliminating the need for a definition of maintenance and testing procedures. PRC-002-2 requirements are performance-based.	

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
DATA SPECIFICATIONS **R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.	**DATA SPECIFICATIONS** **R15.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: **15.1** NERC, Regional Entity, Reliability Coordinator. **15.2** Request from other Transmission Owners, Generator Owners within NPCC. **R16.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: **16.1** The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111. **16.2** Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232. **16.3** Fault Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.	**DATA SPECIFICATIONS** 6.1 Recorded **disturbance** data from DMEs shall be forwarded within 30 days of receipt of the request in each of the following cases: - Request from NERC **Disturbance** Investigation Team - Request from NPCC **Disturbance** Investigation Team - Reliability Coordinator Request 6.2 Data forwarded shall be archived in its native format for a period of 3 years by the TO or GO. 6.3 **Disturbance** data files shall be provided in a format which is capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool (8). 6.4 Disturbance Data files shall be named in conformance with IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 6.5 **Fault** Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station, date, time resolved to milliseconds, SOE point name, status. 6.6 Recorded data from each **disturbance** shall be retrievable for 10 calendar days. This requirement does not apply to **relays** unless those **relays** are designated as DME.	• The stipulation in PRC-002-NPCC-01 Part 15.2 for the provision of data to other Transmission Owners, and Generator Owners in NPCC upon request is addressed by PRC-002-2 in its R15 which mandates the provision of data to the Responsible Entity, RE, or NERC. • PRC-002-NPCC-01's data file requirements specified in R16 are addressed in PRC-002-2 R11. PRC-002-NPCC-01 Part 16.3 requires the provision of information in the data that is incumbent to the data record.	

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
STATUS OF RECORDING CAPABILITY **R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.	**STATUS OF RECORDING CAPABILITY** **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**STATUS OF RECORDING CAPABILITY** **8.0 Maintenance And Testing** Each TO, and GO shall establish a maintenance and testing program for DME (guidance for maintenance and testing is provided in Document B-26) that includes: • Maintenance and testing intervals and their basis. • Summary of maintenance and testing procedures.	• PRC-002-2 addresses “what” data is captured”, not “how” it is captured. This covers the “results” of recording equipment. • PRC-002-2 R12 is more stringent in that it requires a CAP.	

PRC-002-2 REQUIREMENTS	PRC-002-NPCC-01 REQUIREMENTS	A-15	DETERMINATION PRC-002-NPCC-01 NOT NEEDED	DETERMINATION PRC-002-NPCC-01 NEEDED
DATA ON THE DISTURBANCE MONITORING EQUIPMENT Not Applicable.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** **R17.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: **17.1** Type of DME. **17.2** Make and model of equipment. **17.3** Installation location. **17.4** Operational Status. **17.5** Date last tested. **17.6** Monitored Elements. **17.7** All identified channels. **17.8** Monitored electrical quantities.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** 6.7 The TO and GO shall each maintain and be ready to report to NPCC on request the following data on the DMEs installed to meet this standard: - Type of DME - Make and model of equipment - Installation location - Operational Status - Date last tested - Monitored **Elements** - Monitored Devices - Monitored Electrical Quantities	• PRC-002-2 addresses “what” data is captured”, not “how” it is captured. This covers the “results” of recording equipment. Providing data upon request is all that is required. A-15 Section 6.7 addresses the data needed for disturbance monitoring equipment.	

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-006-NPCC-2
Request Date:	03-31-2015

RSAR Requester Information

Name: Brian Robinson		**RSAR Type (Check box for one of these selections.)**	
Company:	NPCC	☐	New Standard
Telephone: 802-241-1400		☒	Revision to Existing Standard
Fax:	(866) 214-8632	☐	Withdrawal of Existing Standard
Email:	Brian.Robinson@utilitysvcs.com	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.**)**

The purpose of the proposed RSAR is to review regional reliability standard PRC-006-NPCC-1 for potential revisions or retirements made necessary by NERC's PRC-006-1/PRC-006-2 Automatic Underfrequency Load Shedding and PRC-024-1/PRC-024-2 Generator Frequency and Voltage Protective Relay Settings standards.

PRC-006-NPCC-1 is to be reviewed to determine if the applicability of the standard needs to be revised in accordance with Project 2014-01 Dispersed Generation Resources.

PRC-006-NPCC-1 is to be reviewed in order to determine if the performance requirements as contained in the criteria of NPCC Directory#12 Sections 5.1.1 and 5.1.2 should be explicitly included in the requirements of the Regional Standard.

Attachment C in PRC-006-NPCC-1 is to be reviewed to address the implications of the design assessment, in accordance with Requirement R4 of PRC-006-1/PRC-006-2, of not meeting the program performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.

PRC-006-NPCC-1 is to be reviewed in order to update Table 4 in Attachment C in accordance with the 2013 NPCC UFLS Adequacy Assessment. Additionally, the applicability of Requirements R4 and R5 will be reviewed to consider that Hydro Quebec is not part of the Eastern Interconnection.

Retiring PRC-006-NPCC-1 is to be considered if it is determined that it can be retired without sacrificing the ability to develop an effective underfrequency load shedding program.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation**.)**

To enhance efficiency and cost effectiveness, it must be determined if PRC-006-NPCC-1 requirements should be revised or retired considering the industry adoption of NERC standards PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2, without sacrificing the ability to preserve the System during declining frequency and voltage excursion events.

OR

To enhance efficiencies and cost effectiveness, it must be determined if PRC-006-NPCC-1 requirements can be revised or retired to address the new NERC BES definition, Paragraph 81, and eliminate redundancy leading to double jeopardy with PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 requirements without sacrificing the ability to develop an effective underfrequency load shedding program.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.**)**

The requirements in PRC-006-NPCC-1 will be reviewed individually for revision or deletion with respect to NERC standards PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2. Both PRC-006-NPCC-1and PRC-006-1/PRC-006-2 mandate effective automatic underfrequency load shedding, and PRC-024-1/PRC-024-2 ensure that generator protective relays are set such that the units remain connected during frequency and voltage excursions. However, there are certain similar requirements in each of these standards that should be reviewed to determine whether there is an opportunity to revise or delete the requirements of PRC-006-NPCC-1 to eliminate redundancy and the resulting double jeopardy.

OR

The requirements in PRC-006-NPCC-1 will be reviewed individually for revision or deletion with respect to the new NERC BES definition, and Paragraph 81. In addition, PRC-006-NPCC-1 will be reviewed against NERC's PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 2-2. PRC-006-1/PRC-006-2 mandate the establishment of design and documentation requirements for automatic underfrequency load shedding (UFLS) programs. PRC-024-1/PRC-024-2 mandate that Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions. These "umbrellas" encompasses the relevant requirements in PRC-006-NPCC-1. However, the relevant requirements in each of the standards are to be compared and the requirements of PRC-006-NPCC-1, if so determined, be revised or deleted to eliminate redundancy and the concomitant double jeopardy. The review will also ensure that NERC Rules of Procedure, Section 312. Regional Reliability Standards, bullet 1that reads "Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard." will govern.

PRC-006-1/PRC-006-2 specifies in Requirement R4 that "Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years…". Revision to Attachment C of PRC-006-NPCC-1 needs to be considered to address the circumstance surrounding a design assessment that does not meet the performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.

Revise Table 4 Attachment C to reflect the modified Quebec UFLS program parameters as recommended in the 2013 NPCC UFLS Adequacy Assessment and review the applicability of Requirements R4 and R5 as they pertain to the Quebec Interconnection.

Additionally, as identified by SS38 there are aspects of the performance requirements in NERC PRC-006-1 that are slightly more relaxed than the criteria in Directory#12 and these more stringent attributes of the NPCC criteria were not incorporated into the regional standard.

Specifically, the NPCC criteria in Directory#12 (Sections 5.1.1 and 5.1.2) state that (1) frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection, and 56.0 Hz for the portion of NPCC in the Quebec Interconnection (2)

frequency should not remain below 59.5Hz for more than 30 seconds and should not remain below 58.5 Hz. for more than 10 seconds. Review the need to include the performance criteria presently in Directory#12 into PRC-006-NPCC-02, or whether the performance criteria included in PRC-006-1/PRC-006-2 is sufficient.

Interpretations of PRC-006-NPCC-1 to be considered to clarify PRC-006-NPCC-2.

The review will include an assessment of the need to include language to address dispersed generation resources.

PRC-006-NPCC-2 should be made to conform to the NERC Results Based Standard format.

~~The review will be governed by bullet 1 of the NERC Rules of Procedure, Section 312, Regional Reliability Standards, which reads "Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard."~~

After this review is completed, it will be determined if PRC-006-NPCC-1 should be revised, or retired.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☒	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☒	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☒	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an Common Attribute of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

Review and compare regional standard PRC-006-NPCC-1with continent-wide standards PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 to determine if revisions are necessary, or retirement of PRC-006-NPCC-01 possible.

Determine the necessity for including wording to address dispersed generation resources.

Consider incorporating more stringent aspects of Directory#12 in order to facilitate future retirement of Directory#12.

Related Standards

Standard No.	Explanation
PRC-006-1/PRC-006-2	NERC Automatic Underfrequency Load shedding

PRC-024-1/PRC-024-2	NERC Generator Frequency and Voltage Protective Relay Settings

Related SARs or RSARs

SAR ID	Explanation

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Submission Description: (doc-less) Motion to Intervene of North American Electric Reliability Corporation under RM15-2-000.

Submission Date: 4/27/2015 1:54:24 PM

Filed Date: 4/27/2015 1:54:24 PM

Dockets

RM15-2-000	Third- Party Provision of primary frequency Response Service.

Filing Party/Contacts:

Filing Party	Signer (Representative)	Other Contact (Principal)
North American Electric Reliability Corporation	Holly.Hawkins@nerc.net	
North American Electric Reliability Corporation		charlie.berardesco@nerc.net

Basis for Intervening:
The North American Electric Reliability Corporation (“NERC”) was formed to serve as the electric reliability organization (“ERO”) authorized by Section 215 of the Federal Power Act. NERC was certified as the ERO by the Commission’s Order issued July 20, 2006, in Docket No. RR06-1-000. As the ERO, NERC is subject to audit by the Commission and governmental authorities in Canada.

NERC has a substantial interest in this proceeding to preserve our rights to file reply comments should the need arise. .

No other party can adequately represent NERC’s interest. Therefore, it is in the public interest to permit this intervention.

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Document Content(s)

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD CIP-014-2

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May 15, 2015

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD CIP-014-2

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA"),[1] Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] and Order No. 802,[3] the North American Electric Reliability Corporation ("NERC")[4] hereby submits for Commission approval proposed Reliability Standard CIP-014-2.[5] Consistent with Order No. 802, proposed Reliability Standard CIP-014-2 modifies Reliability Standard CIP-014-1 by removing the term "widespread" from Requirement R1. As discussed below, removing the term "widespread" will help ensure that: (1) applicable entities identify the appropriate critical facilities under Requirement R1; and (2) the ERO enforces the Reliability Standard in a consistent manner. NERC requests that the Commission approve proposed Reliability Standard CIP-014-2 (Exhibit A) as just, reasonable, not unduly discriminatory, or preferential, and in the public interest.

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1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2014).

3 *Physical Security Reliability Standard*, Order 802, 149 FERC ¶ 61,140 (2014).

4 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006).

5 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards, available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

As required by Section 39.5(a) of the Commission's regulations,[6] this Petition presents the technical basis and purpose of the proposed Reliability Standard, a summary of its development history (Exhibit F), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[7] (Exhibit C). The NERC Board of Trustees adopted proposed Reliability Standard CIP-014-2 and the associated Implementation Plan on May 7, 2015.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[8]

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[6] 18 C.F.R. § 39.5(a) (2014).

[7] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[8] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2014), to allow the inclusion of more than two persons on the service list in this proceeding.

II. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[9] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[10] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[11] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[12] of the Commission's regulations requires the ERO to file for Commission approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to make effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[13] and Section 39.5(c)[14] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

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9 16 U.S.C. § 824o (2006).

10 *Id.* § 824o(b)(1).

11 *Id.* § 824o(d)(5).

12 18 C.F.R. § 39.5(a) (2014).

13 16 U.S.C. § 824o(d)(2).

14 18 C.F.R. § 39.5(c)(1).

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[15] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[16] In certifying NERC as the ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

C. Order No. 802

On November 20, 2014, the Commission issued Order No. 802 approving Reliability Standard CIP-014-1. NERC developed Reliability Standard CIP-014-1 in response to a Commission order issued March 7, 2014 in Docket No. RD14-6-000 directing NERC to submit for approval one or more Reliability Standards to address physical security risks and vulnerabilities of critical facilities on the Bulk-Power System.[17] The Commission found that Reliability Standard CIP-014-1 satisfied the directives in the March 7 Order.

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[15] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[16] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[17] *Reliability Standards for Physical Security Measures*, 146 FERC ¶61,166 (2014) ("March 7 Order").

In addition to approving Reliability Standard CIP-014-1, the Commission directed NERC to remove the term "widespread" from Requirement R1 of CIP-014-1, or alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns related to the term "widespread."[18] In the March 7 Order, the Commission stated that a critical facility is:

> one that, if rendered inoperable or damaged, could have a critical impact on the operation of the interconnection through instability, uncontrolled separation or cascading failures on the Bulk- Power System.

Requirement R1 of CIP-014-1, which addresses the directive in the March 7 Order that owners and operators of the Bulk-Power System perform a risk assessment of their systems to identify their critical facilities, includes much of the language from the March 7 Order with the addition of the term "widespread" before the term "instability." Specifically, CIP-014-1, Requirement R1 provides that Transmission Owners must perform risk assessments:

> designed to identify the Transmission station(s) or Transmission substation(s) that if rendered inoperable or damaged could result in *widespread* instability, uncontrolled separation, or Cascading within an Interconnection. (Emphasis added).

In Order No. 802, the Commission determined that inclusion of the undefined term "widespread" is unclear with respect to the obligation it imposes on applicable entities and introduces excessive uncertainty in identifying critical facilities under Requirement R1.[19] The Commission stated that the identification of critical facilities under Requirement R1 "should not be dependent on how an applicable entity interprets the term 'widespread' but instead should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1."[20]

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18 Order No. 802 at PP 18-19, 31-35.

19 *Id*. at PP 19, 35.

20 *Id*. at P 33.

The Commission directed NERC to submit a responsive modification to address the Commission's concerns within six months from the effective date of Order No. 802, which is May 20, 2015.

D. Procedural History of Proposed Reliability Standard CIP-014-2

As further described in Exhibit F hereto, following the issuance of Order No. 802, NERC posted a revised Standards Authorization Request for a 30-day information comment period to address the directives issued in Order No. 802. On February 20, 2015, NERC posted the proposed Reliability Standard for an initial 45-day comment period and 10-day ballot. The initial ballot received a quorum of 88.33% and an approval of 89.95%. After addressing industry comments on the initial draft of the proposed Reliability Standard, NERC posted the proposed Reliability Standard for a final ballot, which received a quorum of 92% and approval of 92.35%. The NERC Board of Trustees adopted proposed Reliability Standard CIP-014-2 and the associated Implementation Plan on May 7, 2015.

III. JUSTIFICATION FOR APPROVAL

As discussed below and in Exhibit C, proposed Reliability Standard CIP-014-2 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Consistent with Order No. 802, proposed Reliability Standard CIP-014-2 modifies Reliability Standard CIP-014-1 by removing the term "widespread" from Requirement R1. As revised, Requirement R1 reads, in relevant part, as follows:

> Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

Removing the term "widespread" will help provide for more consistent implementation and enforcement of Requirement R1. As the Commission recognized, the term "widespread" is susceptible to varying interpretations and may introduce uncertainty in identifying critical facilities under Requirement R1.[21] Under the proposed Reliability Standard, the identification of critical assets will not depend on the manner in which a particular entity understands the term "widespread"; instead, entities will focus on the critical impact of the facility on the operation of the Interconnection, consistent with the March 7 Order.

The Commission clarified in Order No. 802 that only an instability that has a critical impact on the operation of the interconnection warrants finding that the facility causing the instability is critical under Requirement R1.[22] To provide additional guidance to stakeholders on identifying critical facilities according to Requirement R1, the standard drafting team included the following in the Rationale for Requirement R1 appended to the proposed Reliability Standard:

> The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:
>
> - Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6;
> - NERC EOP-004-2 reporting criteria
> - Area or magnitude of potential impact

[21] Order No. 802 at P 31-33.

[22] *Id*. at P 33.

Aside from removing the term "widespread," NERC did not change any other aspect of Requirement R1.

IV. EFFECTIVE DATE

In the March 7 Order, the Commission stated that "NERC should develop an implementation plan that requires owners or operators of the Bulk-Power System to implement the Reliability Standards in a timely fashion, balancing the importance of protecting the Bulk-Power System from harm while giving the owners or operators adequate time to meaningfully implement the requirements."[23] Consistent with the Commission's directive and as provided in the proposed Implementation Plan, attached hereto as Exhibit B, NERC respectfully requests that the Commission approve proposed Reliability Standard CIP-014-2 to become effective on the later of the first day following the effective date of CIP-014-1 or the first day after the effective date of the Commission's order approving CIP-014-2. The proposed effective date is designed to provide responsible entities regulatory certainty by limiting the time, if any, that CIP-014-1 would be effective.

[23] March 7 Order at P 12.

V. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- proposed Reliability Standard CIP-014-2 and associated elements included in Exhibit A, effective as proposed herein;
- the proposed implementation plan included in Exhibit B; and
- the retirement of Reliability Standard CIP-014-1.

Respectfully submitted,

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Date: May 15, 2015

Exhibit A

Proposed Reliability Standard

CIP-014-2 Clean Version

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-2

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-2.

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or

- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk	Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1	completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	

Guidelines and Technical Basis

Section 4 Applicability

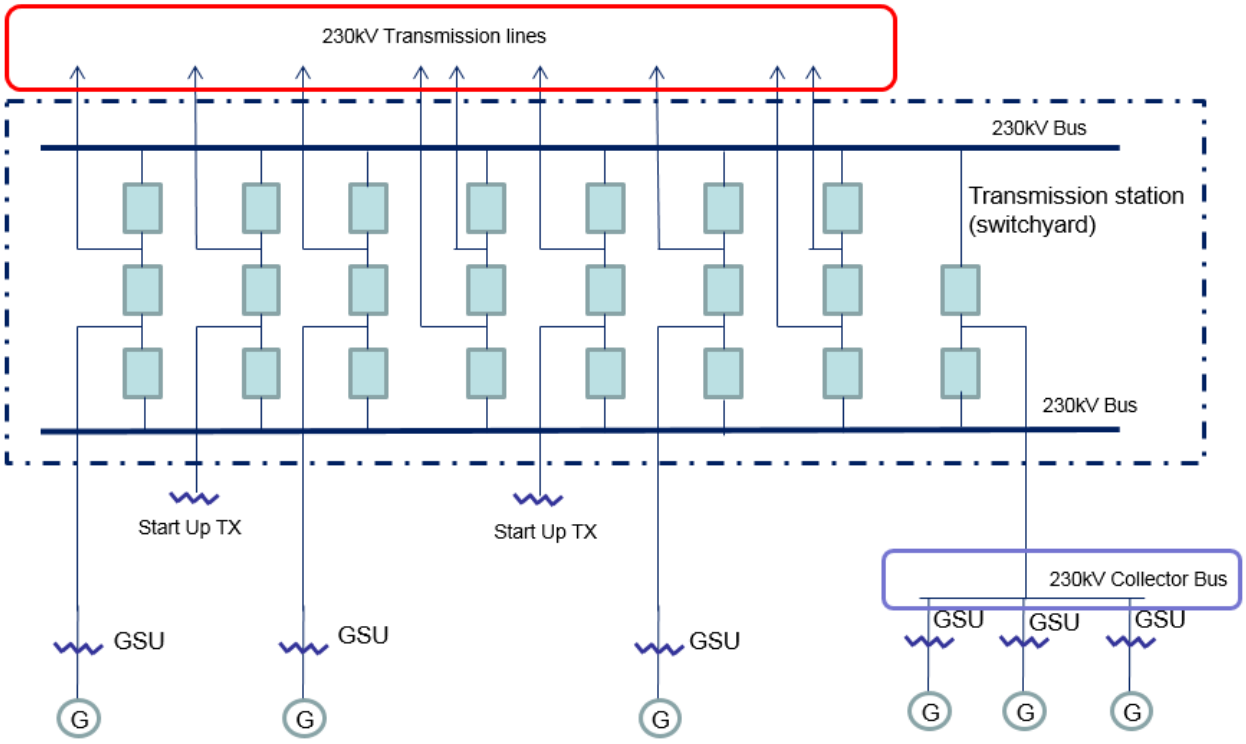
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center

"operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2

is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

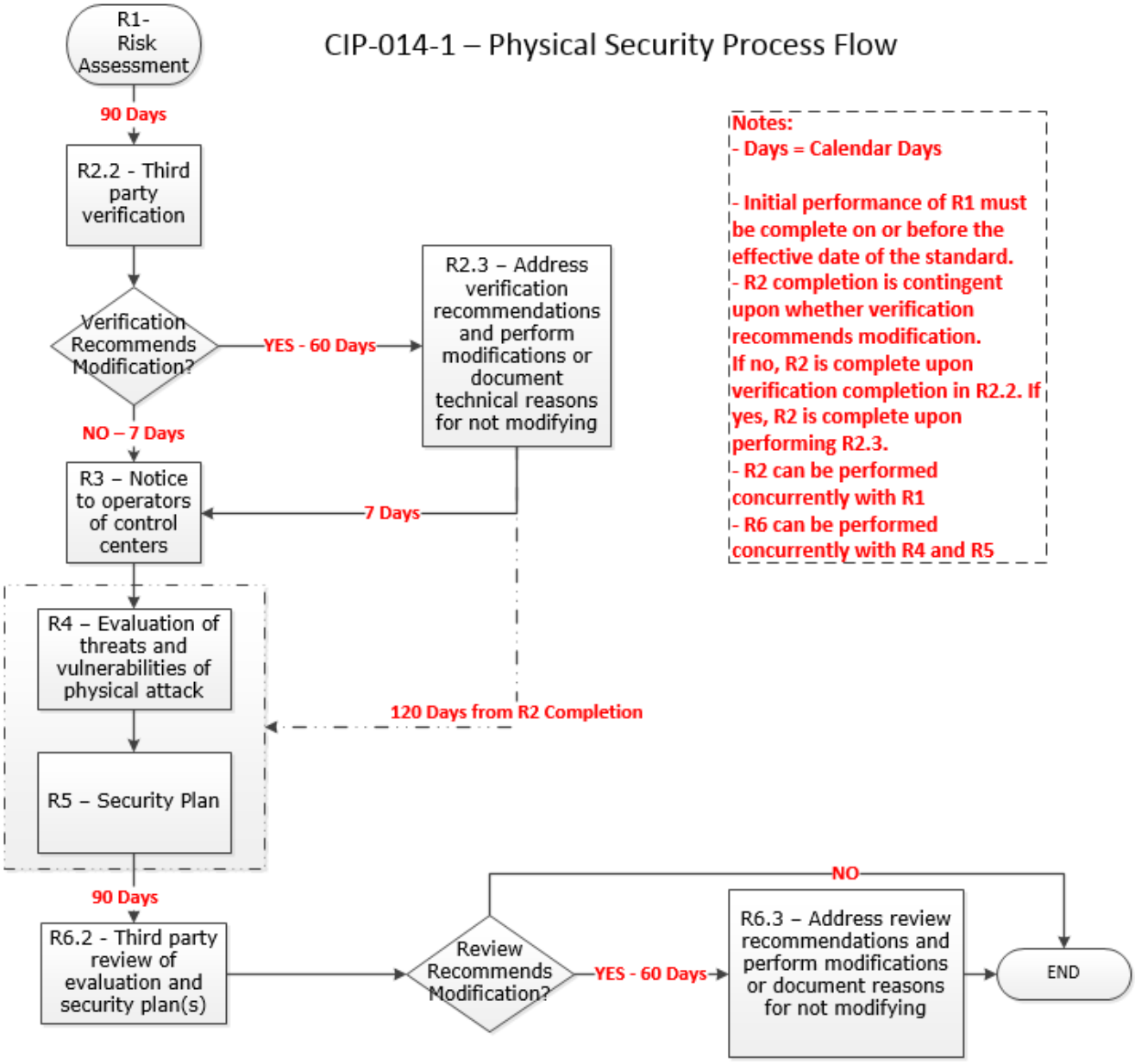
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security

plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

CIP-014-2 Redline Version

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-~~1~~2

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

~~CIP-014-1 is effective the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In those jurisdictions where regulatory approval is not required, CIP-014-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

See Implementation Plan for CIP-014-2.

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner

shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified

Protection Professional (CPP) or Physical Security Professional (PSP) certification.

- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an	result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an	instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection	Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.~~3~~4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	~~May 13, 2014~~October 1, 2015	~~Adopted by NERC Board of Trustees~~Effective Date	New
~~1~~2	~~November 20, 2014~~April 16, 2015	Revised to meet FERC Order ~~approving CIP-014-1~~802 directive to remove "widespread".	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	

Guidelines and Technical Basis

Section 4 Applicability

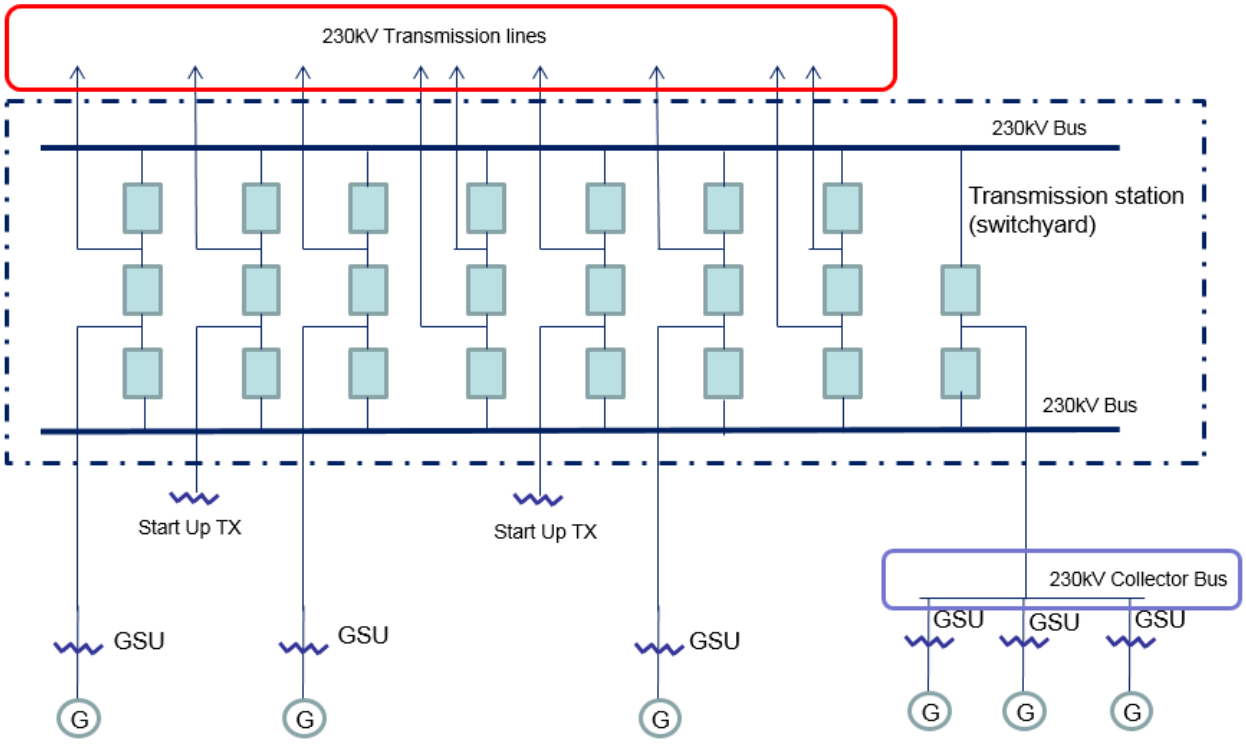
The purpose of Reliability Standard CIP-014~~-1~~ is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014~~-1~~ first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause ~~widespread~~ instability, uncontrolled separation, or Cascading within

an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014~~-1~~. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014~~-1~~, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014~~-1~~ when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014~~-1~~ standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in ~~widespread instability, uncontrolled separation, or Cascading within an Interconnection.~~ instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential ~~widespread~~

instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. ~~–~~Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or

Transmission substation that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated

verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.

5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.

- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.
- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

  Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

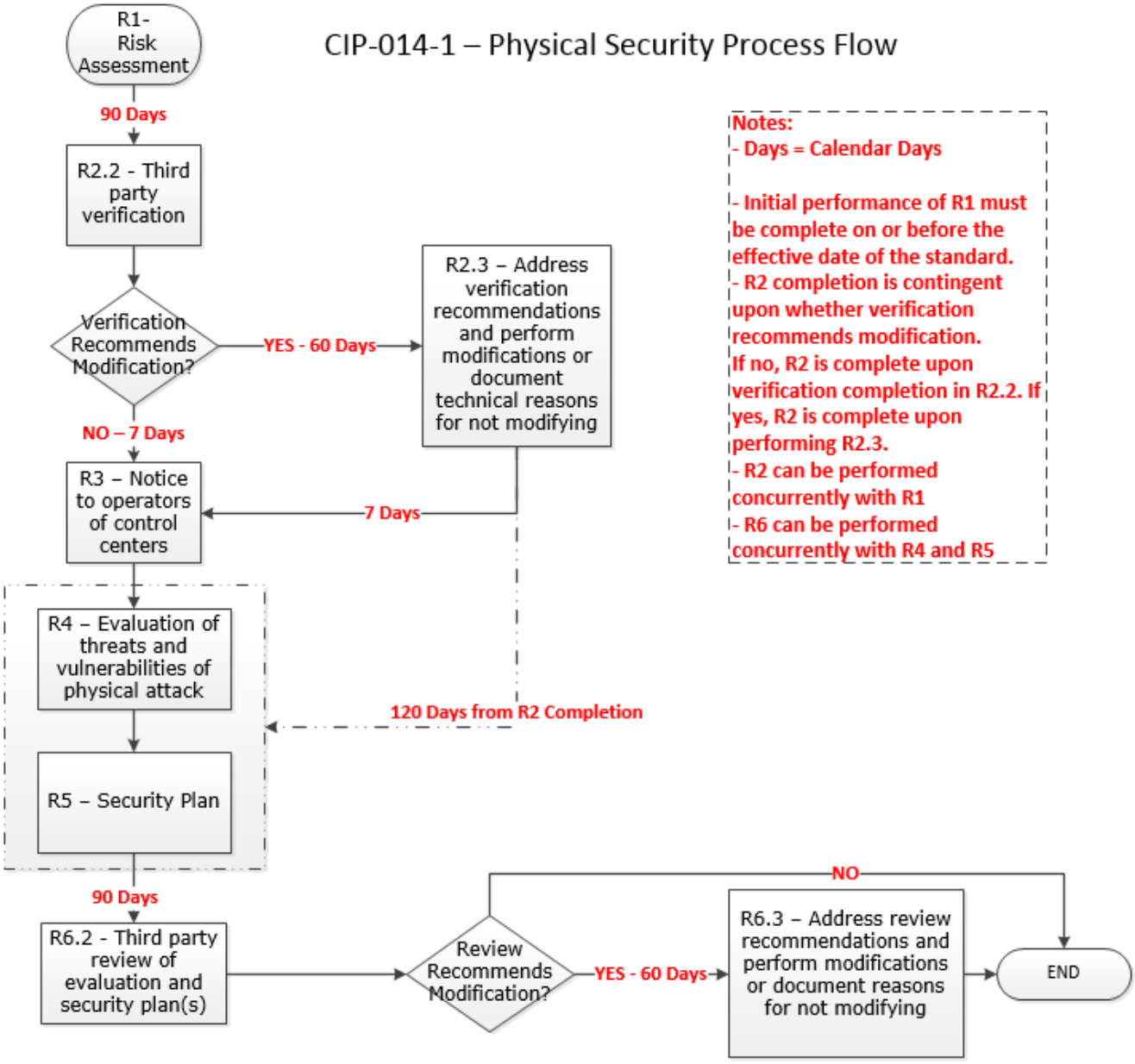
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

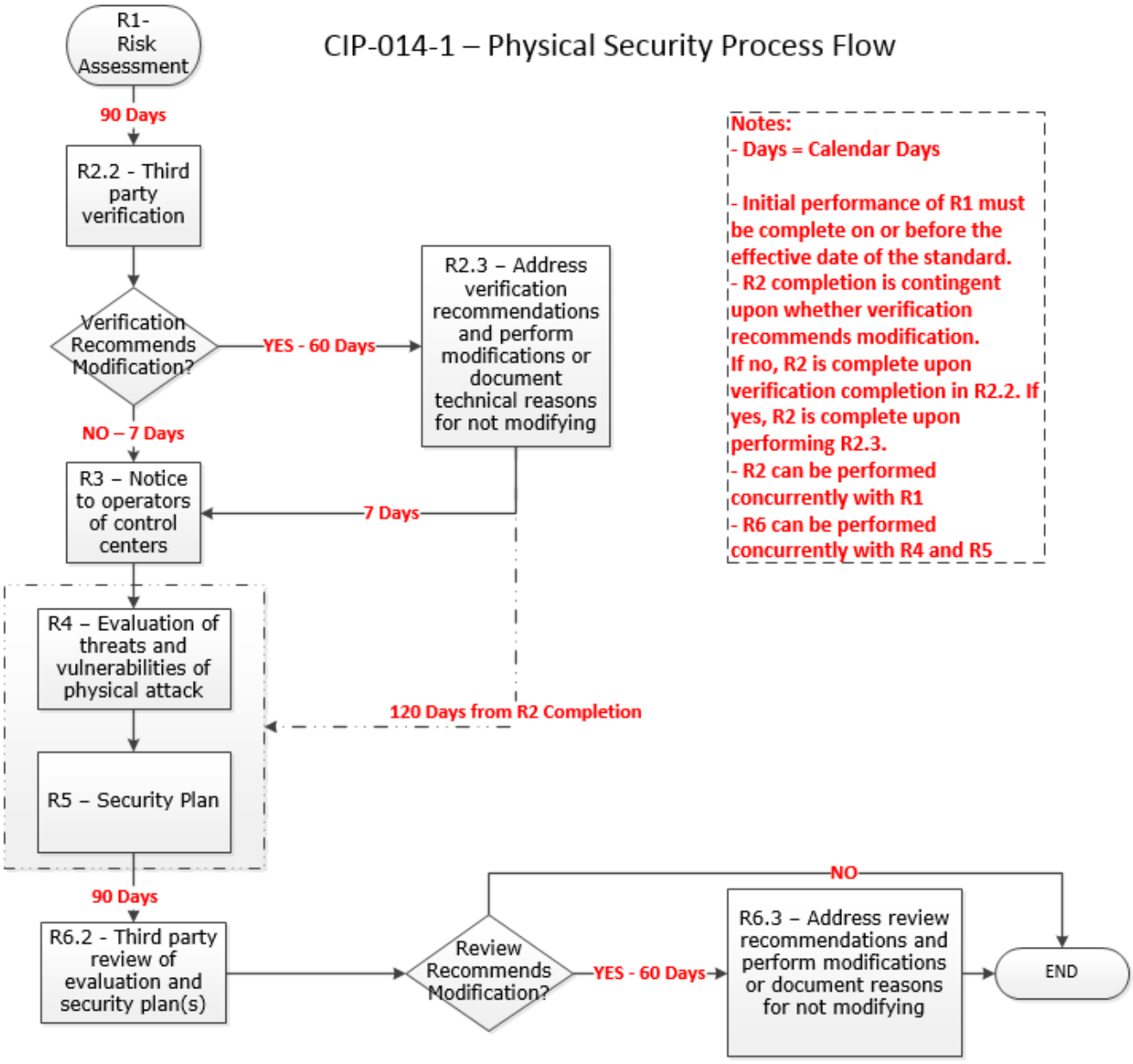
  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5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90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
NO
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale~~:~~

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 ~~in the~~of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through ~~widespread instability, uncontrolled separation, or cascading failures. It also meets the portion of the directive from paragraph 11 for periodic reevaluation~~instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:

This requirement meets the FERC directive from paragraph 8 in the order on physical security

that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:

This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

Exhibit B

Implementation Plan

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Physical Security Directives
CIP-014-2

Standards Involved

Approval:

- CIP-014-2 – Physical Security

Retirement:

- CIP-014-1 – Physical Security

Prerequisite Approvals:

N/A

Background

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

Effective Date

CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day after CIP-014-2 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction

Retirement of Existing Standards:

The existing standard, CIP-014-1, shall be retired at midnight of the day immediately prior to the effective date of CIP-014-2 in the particular jurisdiction in which the revised standard is becoming effective.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Transmission Operator

Implementation of CIP-014-1

All aspects of the Implementation Plan for CIP-014-1 will remain applicable to CIP-014-2 and are incorporated here by reference.

Cross References

The Implementation Plan for CIP-014-1 is available here.

Exhibit C

Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

Proposed Reliability Standard CIP-014-1 achieves the specific reliability goal of enhancing physical security measures for the most critical Bulk-Power System facilities and thereby lessening the overall vulnerability of the Bulk-Power System to physical attacks. The proposed Reliability Standard requires Transmission Owners and Transmission Operators to protect those critical Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

Proposed Reliability Standard CIP-014-2 modifies Reliability Standard CIP-014-1 by removing the term "widespread" from Requirement R1 of the standard. As discussed below, removing the term "widespread" will help ensure that: (1) applicable entities identify the appropriate critical facilities under Requirement R1; and (2) the ERO enforces the Reliability Standard in a consistent manner.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to Transmission Owners and Transmission Operators. The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment, as discussed further in Exhibit E. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

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[3] Order No. 672 at PP 322, 325.

[4] Order No. 672 at P 326.

4. **A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.** [5]

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required to demonstrate compliance. These measures help provide clarity regarding the manner in which the requirements will be enforced, and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.** [6]

The proposed Reliability Standard achieves the reliability goal effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard clearly enumerates the responsibilities of applicable entities with respect to the identification and protection of critical Bulk-Power System facilities and provides entities the flexibility to tailor their processes and plans required under the standard to best suit the needs of their organization.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.** [7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard contains significant benefits for the

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5 Order No. 672 at P 327.

6 Order No. 672 at P 328.

7 Order No. 672 at P 329-30.

Bulk-Power System. The requirements of the proposed Reliability Standard help ensure that entities provide an adequate level of protection against physical attacks to critical facilities.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]**

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]**

The proposed Reliability Standard has no undue negative impact on competition. The proposed Reliability Standard requires the same performance by each applicable entity. The standard does not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. **The implementation time for the proposed Reliability Standard is reasonable.[10]**

The proposed effective date for the standard is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop and implement the necessary procedures and policies. The proposed implementation period will allow applicable entities adequate time to

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[8] Order No. 672 at P 331.

[9] Order No. 672 at P 332.

[10] Order No. 672 at P 333.

meaningfully implement the requirements. The proposed effective date is explained in the proposed Implementation Plan, attached as Exhibit B.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. Exhibit F includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standards. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and additional ballots achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

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[11] Order No. 672 at P 334.

[12] Order No. 672 at P 335.

[13] Order No. 672 at P 323.

Exhibit D

Considerations of Directives

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Directives

Project 2014-04 - Physical Security Directives

April 16, 2015

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 19. In addition to approving Reliability Standard CIP-014-1, the Commission adopts in part the NOPR proposal directing NERC to develop and submit modifications to the Reliability Standard concerning the use of the term "widespread" in Requirement R1. The Commission determines that the term "widespread" is unclear with respect to the obligations it imposes on applicable entities; how it would be implemented by applicable entities; and how it would be enforced. Accordingly, the Commission directs NERC, pursuant to FPA section 215(d)(5), to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. We direct that NERC submit a responsive	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	The Physical Security Standard Drafting Team (PSSDT) revised CIP-014-1, Physical Security, by removing the term "widespread" from the standard. This was done in the Purpose Statement, Background Section, Requirement R1, the Rationale for Requirement R1 as well as the Guidance and Technical Basis Section of the standard. Additionally, the PSSDT has added the following to the Rationale and guideline and Technical Basis for Requirement R1: "The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
modification within six months from the effective date of this final rule. Paragraph 35: Accordingly, pursuant to FPA section 215(d)(5), the Commission directs NERC to develop a modification to Reliability Standard CIP-014-1 that either removes the term "widespread" from Requirement R1 or, in the alternative, proposes changes that address the Commission's concerns. Further, we direct that NERC submit a responsive modification within six months from the effective date of this final rule. We recognize that certain entities commented on how NERC could modify Reliability Standard CIP-014-1 to address the Commission's stated concerns. However, we conclude that it is appropriate to allow NERC to develop and propose a modification in the first instance.		the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following: • Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6 • NERC EOP-004-2 reporting criteria • Area or magnitude of potential impact" Additionally, the PSSDT revised the Rationale for Requirement R1 as follows: "Requirement R1 also meets the directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an interconnection)."

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 21. With respect to the informational filings proposed in the NOPR, the Commission adopts the proposal to direct NERC to make an informational filing addressing whether Reliability Standard CIP-014-1 provides physical security for all "High Impact" control centers, as that term is defined in Reliability Standard CIP-002-5.1, necessary for the reliable operation of the Bulk-Power System. However, the Commission extends the deadline for that informational filing until two years following the effective date of Reliability Standard CIP-014-1. Paragraph 57. The Commission adopts the NOPR proposal and directs NERC to submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers. The Commission, however, modifies the NOPR proposal and extends the due date for the informational filing to two years following the effective date of Reliability Standard CIP-014-1.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1 and R2 with respect to "High Impact" control centers as that term is defined in Reliability Standard CIP-002-5.1 as that term is defined in Reliability Standard CIP-002-5.1. NERC will submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers within two years following the effective date of Reliability Standard CIP-014-1.

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 44. The Commission, instead, will focus its resources on carrying out compliance and enforcement activities to ensure that critical facilities are identified under Requirement R1. In its comments, NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1, R2 and R3 and will submit to the NERC Board of Trustees, a report three months following implementation of these Requirements concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC will also submit this report to Commission staff.

Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2014-04: Physical Security

VRF and VSL Justifications for CIP-014-2

VRF and VSL Justifications – CIP-014-1, R1	
Proposed VRF	High
NERC VRF Discussion	Initial and subsequent risk assessments identify Transmission stations or Transmission substations that need to be assessed for threats and vulnerabilities and potential physical security measures. Since this is a Requirement in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the risk assessment periodicity and the identification of the primary control center that has operational control of Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-002-5.1 R1, which deals with categorizing cyber systems, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date;

VRF and VSL Justifications – CIP-014-1, R1	
	OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.
Proposed Moderate VSL	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.
Proposed High VSL	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date;

VRF and VSL Justifications – CIP-014-1, R1	
	OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.
Proposed Severe VSL	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR

VRF and VSL Justifications – CIP-014-1, R1	
	The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if the risk assessment is not performed or if the risk assessment is not performed within required intervals.
FERC VSL G3 Violation Severity Level Assignment Should Be	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R1	
Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit perform a risk assessment.

VRF and VSL Justifications – CIP-014-1, R2	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party verification of initial and subsequent risk assessments provides reinforcement that the risk assessment was performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party verification including entities that may perform the verification, provisions for adding or removing Transmission stations and/or Transmission substations, and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days following completion of Requirement R1;

VRF and VSL Justifications – CIP-014-1, R2	
	OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.
Proposed Moderate VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.
Proposed High VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by part 2.3.
Proposed Severe VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following completion of Requirement R1; OR

VRF and VSL Justifications – CIP-014-1, R2	
	The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party verification is not performed or if the verification is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4	The VSL is assigned for a single instance of failing to have an unaffiliated third party verification performed; or failing to perform

VRF and VSL Justifications – CIP-014-1, R2	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	the verification within prescribe timelines; or failing to implement procedures to protect information.

VRF and VSL Justifications – CIP-014-1, R3	
Proposed VRF	Lower
NERC VRF Discussion	Notifying the Transmission Operator that it has operational control of a Transmission station or Transmission substation identified in Requirement R1 and verified in Requirement R2 is necessary so that the Transmission Operator may begin performance of subsequent physical security requirements for the primary control center. This is a requirement that is administrative in nature and in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. This justifies a Lower VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the notification of the Transmission Operator regarding the removal of a Transmission station or Transmission substation.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-4 R6, which deals with notifying other entities so that Confirmed Interchange may be implemented, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the

VRF and VSL Justifications – CIP-014-1, R3	
	identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.
Proposed Moderate VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.
Proposed High VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.
Proposed Severe VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR

VRF and VSL Justifications – CIP-014-1, R3	
	The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if notification is not made subject to the conditions of the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on	The VSL is assigned for a single instance of failing to make the appropriate notification.

VRF and VSL Justifications – CIP-014-1, R3	
A Cumulative Number of Violations	

VRF and VSL Justifications – CIP-014-1, R4	
Proposed VRF	Medium
NERC VRF Discussion	Performing an evaluation of potential threats and vulnerabilities of a physical attack to each of respective Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the evaluation of potential threats and vulnerabilities of a physical attack to Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-007-5 R2, which deals with a patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.

VRF and VSL Justifications – CIP-014-1, R4	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.
Proposed High VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.
Proposed Severe VSL	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to conduct an

VRF and VSL Justifications – CIP-014-1, R4	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failed to consider any of the Requirement Parts 4.1-4.3.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failing to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R5	
Proposed VRF	High
NERC VRF Discussion	Development, implementation and execution of a documented physical security plan(s) that covers applicable Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the physical security plan for applicable Transmission stations, Transmission substations, or primary control centers.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-003-3 R4, which deals with implementing and documenting a program to identify, classify, and protect information associated with Critical Cyber Assets, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar

VRF and VSL Justifications – CIP-014-1, R5	
	days but less than or equal to 130 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.
Proposed Moderate VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.
Proposed High VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.
Proposed Severe VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

VRF and VSL Justifications – CIP-014-1, R5	
	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include Parts 5.1 through 5.4 in the plan.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s) or if the responsible entity failed to include any of the Requirement Parts 5.1-5.4.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failing to include any of the Requirement Parts 5.1-5.4.

VRF and VSL Justifications – CIP-014-1, R6	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party review of the threat evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 provides reinforcement that these requirements were performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party review including entities that may perform the review, timelines for completing the review and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days;

VRF and VSL Justifications – CIP-014-1, R6	
	OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.
Proposed Moderate VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.
Proposed High VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not and modify or document the reason for not modifying the security plan(s) as specified in Part 6.3.

VRF and VSL Justifications – CIP-014-1, R6	
Proposed Severe VSL	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party review is not performed or if the review is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R6	
Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to have an unaffiliated third party review performed; or failing to perform the review within prescribe timelines; or failing to implement procedures to protect information.

Exhibit F

Summary of Development and Complete Record of Development

Summary of Development

Summary of Development History

The development record for proposed Reliability Standard CIP-014-2 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived, in part, from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences and all of whom served on the drafting team for Reliability Standard CIP-014-1. A roster of the standard drafting team members is included in Exhibit H.

II. Standard Development History

A. Standard Authorization Request Development

To address the Commission's directives in Order No. 802,[2] NERC revised the Standard Authorization Request ("SAR") approved by the Standards Committee ("SC") for the development of Reliability Standard CIP-014-1. The revised SAR was posted for a 30-day informal comment period from December 15, 2014 through January 13, 2015.

B. First Posting-Formal Comment Period, Ballot and Non-Binding Poll

Proposed Reliability CIP-014-2 was posted for a 45-day formal comment period from February 20, 2015 through April 9, 2015, with an initial ballot held from March 31, 2015 through April 9, 2015. Several documents were posted for guidance with the first draft, including the Unofficial Comment Form, Consideration of Issues and Directives, Mapping Document, and the

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1 16 U.S.C. §824(d) (2) (2006).

2 *Physical Security Reliability Standard*, Order 802, 149 FERC ¶ 61,140 (2014).

Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") Justification Document. The initial ballot received 88.33% quorum, and 89.95% approval. The Non-Binding Poll received 86.33% quorum and 91.20% of supportive opinions. There were 28 sets of responses to the posting, including comments from approximately 80 different individuals from approximately 58 companies representing 9 of the 10 of the industry segments. The comments are available at: http://www.nerc.com/pa/Stand/Prjct201404PhsclScrty/Project_2014-04_Physical_Security_CIP-014-2_Consideration_of_Comments_04202015.pdf.

C. Final Ballot

Proposed Reliability Standard CIP-014-2 was posted for a 10-day final ballot period from April 20, 2015 through April 29, 2015. The proposed Reliability Standard received a quorum of 92.00% and 92.35% approval.

D. Board of Trustees Approval

Proposed Reliability Standard CIP-014-2 was approved by NERC Board of Trustees on May 7, 2015.

Complete Record of Development

Project 2014-04 Physical Security

Related Files

Status
A final ballot for **CIP-014-2 – Physical Security** concluded at **8 p.m. Eastern on Wednesday, April 29, 2015**. Voting results can be accessed via the links below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Board Adopted: CIP-014-1 - May 13, 2014

Filed with FERC: CIP-014-1 - May 23, 2014

US Enforcement Date

Filings and Orders

Background
CIP-014-2: In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, the Federal Energy Regulatory Commission (FERC) directed NERC to remove the term “widespread” from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address FERC’s concerns. FERC directed that NERC submit a responsive modification on July 27, 2015.

CIP-014-1: This project will address the directives issued in the FERC Order on Reliability Standards for Physical Security Measures under Docket No. RD14-6-000 issued March 7, 2014. The Commission directed "The North American Electric Reliability Corporation (NERC), as the Commission-certified Electric Reliability Organization (ERO), to submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System. The proposed Reliability Standards should require owners or operators of the Bulk-Power System, as appropriate, to identify facilities on the Bulk-Power System that are critical to the reliable operation of the Bulk-Power System. Then, owners or operators of those identified critical facilities should develop, validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities. The Commission directs NERC to submit the proposed Reliability Standards to the Commission within 90 days of the date of this order."

Standard(s) Affected - CIP-014-1, CIP-014-2

Purpose / Industry Need
CIP-014-2: FERC noted that incorporating the undefined term “widespread” in Reliability Standard CIP-014-1 introduces excessive uncertainty in identifying critical facilities under Requirement R1. As FERC stated in its earlier March 7, 2014 Order, only an instability that has a “critical impact on the operation of the interconnection” warrants finding that the facility causing the instability is critical under Requirement R1. The March 7 Order did not intend to suggest that the physical security Reliability Standards should address facilities that do not have a “critical impact on the operation of the interconnection.” FERC stated that this understanding is unintentionally absent in Requirement R1 because the requirement only deems a facility critical when, if rendered inoperable or damaged, it could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. The definition in Requirement R1 should not be dependent on how an applicable entity interprets the term “widespread” but instead should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1.

CIP-014-1: From the Order: "Physical attacks to the Bulk-Power System can adversely impact the reliable operation of the Bulk-Power System, resulting in instability, uncontrolled separation, or cascading failures. However, the current Reliability Standards do not specifically require entities to take steps to reasonably protect against physical security attacks on the Bulk-Power System. Therefore, to carry out section 215 of the FPA and to provide for the reliable operation of the Bulk-Power System, the Commission directs the ERO to develop and file for approval proposed Reliability Standards that address threats and vulnerabilities to the physical security of critical facilities on the Bulk-Power System. Such Reliability Standards will enhance the Commission's ability to assure the public that critical facilities are reasonably protected against physical attacks."

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **CIP-014-2** Clean **(22)** | Redline to Last Posted **(23)** Redline to Last Approved **(24)** Implementation Plan **(25)** **Supporting Materials** **Consideration of Directives** Clean **(26)**| Redline to Last Posted **(27)** Mapping Document **(28)** **VRF/VSL Justifications** Clean **(29)** | Redline to Last Posted **(30)** **Draft RSAW** Clean | Redline to Last Posted	Final Ballot Info **(31)** Vote	04/20/15 - 04/29/15	Summary **(32)** Ballot Results **(33)**	

Draft 1 CIP-014-2 Clean **(7)** | Redline to Last Approved **(8)** (CIP-014-1) Implementation Plan **(9)** **Supporting Materials** Unofficial Comment Form (Word) **(10)** Consideration of Issues and Directives **(11)** Mapping Document **(12)** VRF/VSL Justification **(13)** **Draft RSAW** Clean | Redline to Last Posted	Initial Ballot and Non-binding Poll Updated Info **(14)** Info **(15)** Vote	03/31/15 - 04/09/15	Summary **(17)** Ballot Results **(18)** Non-binding Poll Results **(19)**	
	Comment Period Info **(16)** Submit Comments	02/20/15 - 04/09/15	Comments Received **(20)**	Consideration of Comments **(21)**
	Join Ballot Pool **Note:** If you had previously joined the ballot pools for CIP-014-1, you **must** join these ballot pools to cast a vote. Previous CIP-014-1 ballot pool members **have not** been carried over to these ballot pools	02/20/15 - 03/23/15		
	Send RSAW feedback to: RSAWfeedback@nerc.net	02/20/15 - 04/09/15		
Standard Authorization Request (SAR)	Comment Period Info **(4)**	12/15/14 – 1/13/15	Comments Received **(5)**	Consideration of Comments **(6)**

Clean **(1)** | Redline to Last Posted **(2)** **Supporting Materials** Unofficial Comment Form (Word) **(3)**	Submit Comments			
CIP-014-1 Clean | Redline to Last Posted Implementation Plan **Supporting Materials** **Consideration of Issues and Directives** Clean | Redline to Last Posted VRF/VSL Justifications **Draft RSAW** Clean | Redline to Last Posted	Final Ballot Info Vote	05/01/14 - 05/05/14	Summary Ballot Results	
CIP-014-1 Implementation Plan **Supporting Materials** Project Overview	Initial Ballot and Non-binding Poll Updated Info Info	04/20/14 - 04/24/14	Summary Ballot Results Non-binding Poll Results	

FAQ Unofficial Comment Form (Word) Consideration of Issues and Directives Draft RSAW	Vote			Consideration of Comments
	Comment Period Info Submit Comments	04/10/14 - 04/24/14	Comments Received	
	Join Ballot Pool	04/10/14 - 04/19/14		
	Please send feedback on the draft RSAW to: RSAWfeedback@nerc.net	04/10/14 - 04/24/14		
Standards Authorization Request **Supporting Materials** Unofficial Comment Form (Word)	Comment Period Info Submit Comments	03/21/14 – 03/28/14	Comments Received	
	Join Ballot Pool			
Supporting Materials Nomination Form (Word)	Nomination Period Info Submit Nominations	03/12/14 - 03/18/14		

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Standards Authorization Request Form

When completed, email this form to:
Barbara.Nutter@nerc.net

For questions about this form or for assistance in completing the form, call Barb Nutter at 404-446-9692.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-04 Physical Security Reliability Standard(s)		
Date Submitted:	March 12, 2014 (revised November 20, 2014)		
SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC Staff		
Telephone:	609-651-9455	E-mail:	Stephen.crutchfield@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On March 7, 2014, FERC issued an order directing the ERO to develop a standard to address the physical security of critical facilities on the Bulk-Power System. In the order, FERC stated: "The Commission directs the North American Electric Reliability Corporation (NERC), as the Commission-certified Electric Reliability Organization (ERO), to submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System. The proposed Reliability Standards should require owners or operators of the Bulk-Power System, as appropriate, to identify facilities on the Bulk-Power System that are critical to the reliable operation of the Bulk-Power System. Then, owners or operators of those identified critical facilities should develop, validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities. The Commission directs NERC to submit the proposed Reliability Standards to the Commission within 90 days of the date of this order." *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 at P 1 (2014) ("FERC Order"). In Order No. 802 (final order on CIP-014-1), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-04, Physical Security to develop a standard(s) to address the directives of the March 7, 2014 FERC Order, and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802, and to ensure consistency within the NERC body of Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standard(s) to address the directives in the March 7, 2014 FERC Order regarding the physical security of critical facilities on the Bulk-Power System, and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802.

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall develop standard requirements, Violation Risk Factors, Violation Severity Levels, and implementation plan and shall work with compliance on an accompanying RSAW to address each of the directives in the March 7, 2014 FERC Order and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to address each of the FERC directives in the deadline required by the Order and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802. The reliability assessment and justification is also set forth in the March 7, 2014 FERC Order. The March 7, 2014 FERC Order is incorporated in its entirety into this SAR, so as not to unnecessarily repeat or paraphrase the substance of the Order. There are no market interface impacts resulting from the standard action on physical security.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions	
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☐ Generator Owner	Owns and maintains generation facilities.
☐ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
CIP-006-5 CIP-008-5 CIP-009-5	Review to ensure no language and terminology inconsistency with requirements developed under this project.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A

Regional Variances	
WECC	N/A

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Proposed Standard:	Project 2014-04 Physical Security Reliability Standard(s)		
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SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC Staff		
Telephone:	609-651-9455	E-mail:	Stephen.crutchfield@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
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Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
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Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
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☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
CIP-006-5 CIP-008-5 CIP-009-5	Review to ensure no language and terminology inconsistency with requirements developed under this project.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A

Regional Variances	
WECC	N/A

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Unofficial Comment Form

Project 2014-04 Physical Security

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft CIP-014-1 Reliability Standard. The electronic comment form must be completed by 8:00 p.m. ET on **January 13, 2015.**

If you have questions please contact Stephen Crutchfield via email or by telephone at stephen.crutchfield@nerc.net or 609-651-9455.

The project page may be accessed by clicking here.

Background Information

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

FERC noted that incorporating the undefined term "widespread" in Reliability Standard CIP-014-1 introduces excessive uncertainty in identifying critical facilities under Requirement R1. As the Commission stated in the March 7 Order, only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1. The March 7 Order did not intend to suggest that the physical security Reliability Standards should address facilities that do not have a "critical impact on the operation of the interconnection." This understanding is, we believe, unintentionally absent in Requirement R1 because the requirement only deems a facility critical when, if rendered inoperable or damaged, it could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. The definition in Requirement R1 should not be dependent on how an applicable entity interprets the term "widespread" but instead should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1.

You do not have to answer all questions below. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained. Due to the expected volume of comments, the SDT asks that commenters consider consolidating responses and endorsing comments provided by another.

Questions

1. The SAR for Project 2014-04 (the original project for the CIP-014-1, Physical Security standard) was revised to adderss the directive from FERC to to remove the term “widespread” from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission’s concerns. Do you agree with the proposed revisions to the SAR? If not, please provide specific comments regarding the SAR.

   ☐ Yes
   ☐ No

   Comments:

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Standards Announcement

Project 2014-04 Physical Security Standard Authorization Request

Informal Comment Period Now Open through January 13, 2015

Now Available

A 30-day informal comment period for the **Project 2014-04 Physical Security** Standard Authorization Request (SAR) is open through **8 p.m. Eastern on Tuesday, January 13, 2015.**

Instructions for Commenting

The comment period is open through **8 p.m. Eastern on Tuesday, January 13, 2015.** Please use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Stephen Crutchfield, Standards Developer, or at 609-651-9455.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (18 Responses)
Name (10 Responses)
Organization (10 Responses)
Group Name (8 Responses)
Lead Contact (8 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (0 Responses)
Comments (18 Responses)
Question 1 (18 Responses)
Question 1 Comments (18 Responses)

Individual
Chris Scanlon
Exelon
Yes
The Exelon Companies, PECO, ComEd and BGE, agree that removing “Widespread” from the text of the standard satisfies the concerns raised by FERC. We believe this is an efficient and effective approach to clarify the standard language and complete the Project so that implementation can begin in earnest.
Individual
Amy Casuscelli
Xcel Energy
Yes
Individual
Mike Smith
Manitoba Hydro
Yes
No comment.
Group
Tennessee Valley Authority
Dennis Chastain
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Individual
Mark Wilson
Independent Electricity System Operator
Yes

Group
Bonneville Power Administration
Andrea Jessup
Yes
BPA has no issues with the removal of the term “widespread” since it is not used elsewhere and is not a Continent-wide Term referenced in the NERC Glossary of Terms Used in Reliability Standards. However, NERC needs to be very clear and concise as to how they define a facility as “critical” and what constitutes “critical impact” to the interconnection to ensure there is no room for interpretation among entities. BPA believes that the definition in Requirement R1 should not be dependent on how an applicable entity interprets the term “widespread” but instead should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1.
Individual
Mike Smith
Manitoba Hydro
Yes
No comments.
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
Yes
Individual
David Thorne
Pepco Holdings Inc.
Yes
Group
Dominion
Connie Lowe
Yes
Individual
David Kiguel
David Kiguel
Yes
The SAR Information Section states that "The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-04, Physical Security to develop a standard(s) to address the directives of the March 7, 2014 FERC Order ….." This Section should be modified to reflect the fact that the purpose of the SAR is to allow the SDT to modify the requirements of the existing Standard CIP-014-1 (Physical Security) to address the directives of FERC.
Individual
Andrew Z. Pusztai

American Transmission Company, LLC
Yes
Individual
David Jendras
Ameren
Yes
Group
Duke Energy
Michael Lowman
Yes
Duke Energy agrees with the proposed revisions to the SAR, including the removal of the term “widespread” from the standard. In FERC Order 802, the Commission directed NERC to remove the term “widespread”, or in the alternative, propose specific modifications to the Reliability Standard that address the Commission’s concerns. Duke Energy recommends that if the drafting team considers making modifications to the Standard to address the FERC’s concerns, that the team consider inserting the language “critical impact on the operation of the interconnection” into the Standard. We feel that this language helps clarify and narrow down possible interpretations of what constitutes instability within an interconnection.
Group
ACES Standards Collaborators
Jason Marshall
Yes
We agree the proposed changes to the SAR address the Commission directive. However, we caution the drafting team to consider carefully how simply removing “widespread” could alter the original intent of the requirement. Widespread was added to reflect that there can be local stability issues that will not jeopardize the reliability of the overall bulk electric system. If the loss of Transmission substation or station will only cause a local stability issue, we do not believe it should be identified as requiring physical security measures. We believe this view is consistent with the intent of original FERC order directing the creation of the standard.
Group
Large Public Power Council
Joe Tarantino
Yes
The members of the Large Public Power Council agree with either the removal or modification of the word “widespread” in the Physical Security Standard to address the Commission’s concern. However, we urge the Standard Drafting Team to address the following: Any clarification made to the CIP-014 Standard should be consistent with current applicable standards, for example in the TPL-001-4 standard Requirement R6 requires the Transmission Planner and Planning Coordinator to define their criteria or methodology used in the analysis for the identification of System instability. This approach should not subject certain Facilities to the CIP-014 standard where acceptable conditions are met through acceptable performance criteria identified by the TP/PC and thereby would not deem a particular Facility as having a critical impact on the operation of the interconnection. Additionally, some degree of flexibility may be necessary across regions. Performance characteristics are potentially different between the Eastern Interconnect and the Western Interconnect; one region may be more sensitive to frequency stability while the other may be more sensitive to voltage

stability. Those Regional differences would be considered/accounted for through the TP/PC's documentation of System instability (TPL-001-4 R6).
Group
SPP Standards Review Group
Robert Rhodes
No
While we may agree with the removal of the term 'widespread' we at the same time have concerns that the intent that widespread gives the standard be captured in additional language to include specificity and structure in the standard. We don't need the standard to be about capturing small, insignificant events but at the same time we need to be sure we are capturing the events that need to be captured. We also need to be sure that anything that is added does not conflict and is consistent with existing standards such as TPL-001-4, R6. The phrase '…on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802.' should be rewritten as '…on the removal of the term "widespread" or alternatively propose modifications that address the Commission's comcerns in Order 802.' for consistency with its use in the 3rd paragraph in the Industry Need section. Should the Load-Serving Entity be deleted from the list of Reliability Functions in the SAR?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2014-04 Physical Security

The Physical Security Drafting Team thanks all commenters who submitted comments on the Standard Authorization Request (SAR). The SAR was posted for a 30-day public comment period from December 15, 2014 through January 13, 2015. Stakeholders were asked to provide feedback on the SAR through a special electronic comment form. There were 17 sets of comments, including comments from approximately 59 different people from approximately 58 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew via email, or by telephone at (404) 446-2566. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration: All those submitting comments agreed with the proposed revisions to the SAR. Several comments suggested that the drafting team consider making revisions to the standard in addition to simply removing the term "widespread" from the standard. These comments suggest modifying CIP-014-1 to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1. Another comment suggested that any clarification made to the CIP-014 Standard should be consistent with current applicable standards; for example in the TPL-001-4 standard Requirement R6 requires the Transmission Planner and Planning Coordinator to define their criteria or methodology used in the analysis for the identification of System instability. These comments will be forwarded to the PSSDT for their consideration. Another comment suggested revising the SAR Information Section which states that "The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-04, Physical Security to develop a standard(s) to address the directives of the March 7, 2014 FERC Order ....." The comment suggested modifying this to reflect the fact that the purpose of the SAR is to allow the SDT to modify the requirements of the existing Standard CIP-014-1 (Physical Security) to address the directives of FERC. The PSSDT believes that the existing language is sufficient and has elected to not revise the SAR.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

1. The SAR for Project 2014-04 (the original project for the CIP-014-1, Physical Security standard) was revised to address the directive from FERC to to remove the term “widespread” from Reliability Standard CIP-014-1 or, alternatively, to propose modificatons to the Reliability Standard that address the Commission’s concerns. Do you agree with the proposed revisions to the SAR? If not, please provide specific comments regarding the SAR. 8

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	Brandy Spraker		SERC	5
4.	Marjorie Parsons		SERC	6

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Helen Lainis	Independent Electricity System Operator	NPCC	2
11.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

3.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neil Arthurs	Physical Security	WECC	1
2.	Tim Eubank	System Operations	WECC	1

4.	Group	Connie Lowe	Dominion	X		X		X	X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randi Heise	NERC Compliance Policy	NPCC	5, 6
2.	Louis Slade	NERC Compliance Policy	RFC	5, 6
3.	Larry Nash	Electric Transmission Compliance	SERC	1, 3, 5, 6

5.	Group	Michael Lowman	Duke Energy	X		X		X	X			

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Gerg Cecil		RFC	6

6.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1
2.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
3.	Chip Koloini	Golden Spread Electric Cooperative	SPP	3, 5
4.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6.	Ginger Mercier	Prairie Power	SERC	3
7.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
8.	Sarah Snow	South Mississippi Electric	SERC	1, 3, 4, 6

7.	Group	Joe Tarantino	Large Public Power Council	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.		Austin Energy	ERCOT	1, 3, 4, 5, 6
2.		Chelan PUD	WECC	1, 3, 5, 6
3.		Clark PUD	WECC	1
4.		Colorado Springs	WECC	1, 3, 6
5.		Grant PUD	WECC	1, 3, 5
6.		Grant PUD	SPP	NA
7.		Jacksonville (JEA)	FRCC	1, 3, 5
8.		Long Island	NPCC	1
9.		Los Angeles DWP	WECC	1, 3, 5, 6
10.		CPS Energy	ERCOT	1, 3, 5
11.		Electricities North Carolina	SERC	3, 6
12.		Lower Colorado River Authority	ERCOT	1, 5
13.		MEAG	SERC	1, 3, 5
14.		Nebraska PPD	MRO	1, 3, 5
15.		New York Power Authority	NPCC	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
16.		Omaha PPD	MRO 1, 3, 5, 6										
17.		Orlando (OUC)	FRCC 1, 3, 5, 6										
18.		Platte River Power Authority	WECC 1, 3, 5, 6										
19.		Salt River Project	WECC 1, 3, 5, 6										
20.		Santee Cooper	SERC 1, 3, 5, 6										
21.		Seattle City Light	WECC 1, 3, 4, 5, 6										
22.		Snohomish County PUD	WECC 1, 3, 4, 5, 6										
23.		Tacoma Public Utilities	WECC 1, 3, 4, 5, 6										
8.	Individual	Chris Scanlon	Exelon	X		X		X	X				
9.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
10.	Individual	Mike Smith	Manitoba Hydro	X		X		X	X				
11.	Individual	Mark Wilson	Independent Electricity System Operator		X								
12.	Individual	Mike Smith	Manitoba Hydro	X		X		X	X				
13.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
14.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
15.	Individual	David Kiguel	David Kiguel								X		
16.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
17.	Individual	David Jendras	Ameren	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: N/A

Organization	Agree	Supporting Comments of "Entity Name"
N/A	N/A	N/A

1. The SAR for Project 2014-04 (the original project for the CIP-014-1, Physical Security standard) was revised to address the directive from FERC to to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. Do you agree with the proposed revisions to the SAR? If not, please provide specific comments regarding the SAR.

Summary Consideration: All those submitting comments agreed with the proposed revisions to the SAR. Several comments suggested that the drafting team consider making revisions to the standard in addition to simply removing the term "widespread" from the standard. These comments suggest modifying CIP-014-1 to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1. Another comment suggested that any clarification made to the CIP-014 Standard should be consistent with current applicable standards; for example in the TPL-001-4 standard Requirement R6 requires the Transmission Planner and Planning Coordinator to define their criteria or methodology used in the analysis for the identification of System instability. These comments will be forwarded to the PSSDT for their consideration. Another comment suggested revising the SAR Information Section which states that "The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-04, Physical Security to develop a standard(s) to address the directives of the March 7, 2014 FERC Order ....." The comment suggested modifying this to reflect the fact that the purpose of the SAR is to allow the SDT to modify the requirements of the existing Standard CIP-014-1 (Physical Security) to address the directives of FERC. The PSSDT believes that the existing language is sufficient and has elected to not revise the SAR.

Organization	Yes or No	Question 1 Comment
Tennessee Valley Authority	Yes	
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	BPA has no issues with the removal of the term "widespread" since it is not used elsewhere and is not a Continent-wide Term referenced in the NERC Glossary of Terms Used in Reliability Standards. However, NERC needs to be very clear and concise as to how they define a facility as "critical" and what constitutes "critical impact" to the interconnection to ensure there is no

Organization	Yes or No	Question 1 Comment
		room for interpretation among entities. BPA believes that the definition in Requirement R1 should not be dependent on how an applicable entity interprets the term "widespread" but instead should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1.
Dominion	Yes	
Duke Energy	Yes	Duke Energy agrees with the proposed revisions to the SAR, including the removal of the term "widespread" from the standard. In FERC Order 802, the Commission directed NERC to remove the term "widespread", or in the alternative, propose specific modifications to the Reliability Standard that address the Commission's concerns. Duke Energy recommends that if the drafting team considers making modifications to the Standard to address the FERC's concerns, that the team consider inserting the language "critical impact on the operation of the interconnection" into the Standard. We feel that this language helps clarify and narrow down possible interpretations of what constitutes instability within an interconnection.
ACES Standards Collaborators	Yes	We agree the proposed changes to the SAR address the Commission directive. However, we caution the drafting team to consider carefully how simply removing "widespread" could alter the original intent of the requirement. Widespread was added to reflect that there can be local stability issues that will not jeopardize the reliability of the overall bulk electric system. If the loss of Transmission substation or station will only cause a local stability issue, we do not believe it should be identified as requiring physical security measures. We believe this view is consistent with the intent of original FERC order directing the creation of the standard.
Large Public Power Council	Yes	The members of the Large Public Power Council agree with either the removal or modification of the word "widespread" in the Physical Security

Organization	Yes or No	Question 1 Comment
		Standard to address the Commission's concern. However, we urge the Standard Drafting Team to address the following: Any clarification made to the CIP-014 Standard should be consistent with current applicable standards, for example in the TPL-001-4 standard Requirement R6 requires the Transmission Planner and Planning Coordinator to define their criteria or methodology used in the analysis for the identification of System instability. This approach should not subject certain Facilities to the CIP-014 standard where acceptable conditions are met through acceptable performance criteria identified by the TP/PC and thereby would not deem a particular Facility as having a critical impact on the operation of the interconnection. Additionally, some degree of flexibility may be necessary across regions. Performance characteristics are potentially different between the Eastern Interconnect and the Western Interconnect; one region may be more sensitive to frequency stability while the other may be more sensitive to voltage stability. Those Regional differences would be considered/accounted for through the TP/PC's documentation of System instability (TPL-001-4 R6).
Exelon	Yes	The Exelon Companies, PECO, ComEd and BGE, agree that removing "Widespread" from the text of the standard satisfies the concerns raised by FERC. We believe this is an efficient and effective approach to clarify the standard language and complete the Project so that implementation can begin in earnest.
Xcel Energy	Yes	
Manitoba Hydro	Yes	No comment.
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	No comments.
Seminole Electric Cooperative, Inc.	Yes	
Pepco Holdings Inc.	Yes	
David Kiguel	Yes	The SAR Information Section states that "The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-04, Physical Security to develop a standard(s) to address the directives of the March 7, 2014 FERC Order ....." This Section should be modified to reflect the fact that the purpose of the SAR is to allow the SDT to modify the requirements of the existing Standard CIP-014-1 (Physical Security) to address the directives of FERC.
American Transmission Company, LLC	Yes	
Ameren	Yes	

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. A revised SAR was approved by the Standards Committee on December 9, 2014 to address the directives issued in FERC Order No. 802 issued on November 20, 2014, in Docket No. RD14-15-000, *Physical Security Reliability Standard*, 146 FERC ¶ 61,140 (2014). The appointed Physical Security Standard Drafting Team made the revisions to the standard.

Description of Current Draft

This is the first draft of the proposed Reliability Standard, and it is being posted for a 45-day comment and concurrent initial ballot period. This draft includes proposed revisions to address the directives issued in FERC Order No. 802.

Anticipated Actions	Anticipated Date
45-day Comment and Initial Ballot.	February-March, 2015
10-day Final Ballot.	April, 2015
BOT Adoption.	May, 2015
File with applicable Regulatory Authorities.	June, 2015

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-1

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-2.

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or

- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or

- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The

term “unaffiliated” means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term “unaffiliated” is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

Rationale for Requirement R3:

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission

Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

Rationale for Requirement R4:

This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function,

existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

Rationale for Requirement R5:

This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

Rationale for Requirement R6:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk	Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1	completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 Applicability

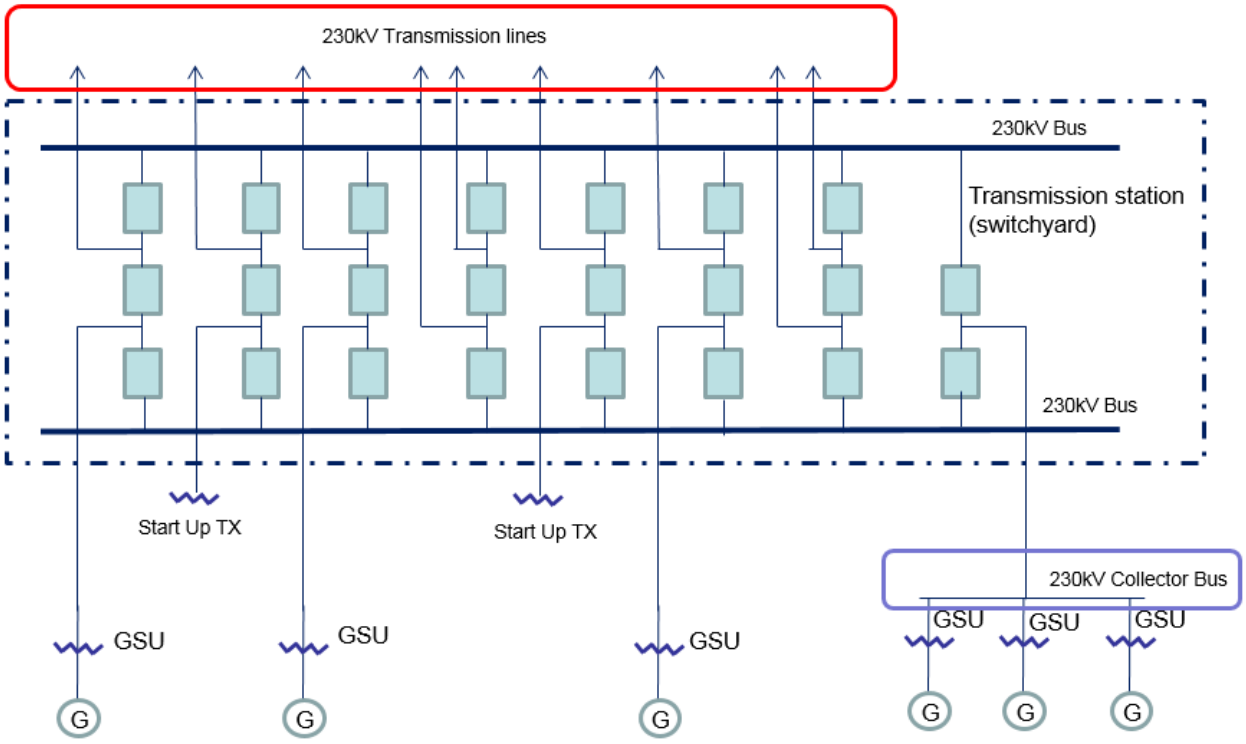
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center

"operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2

is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

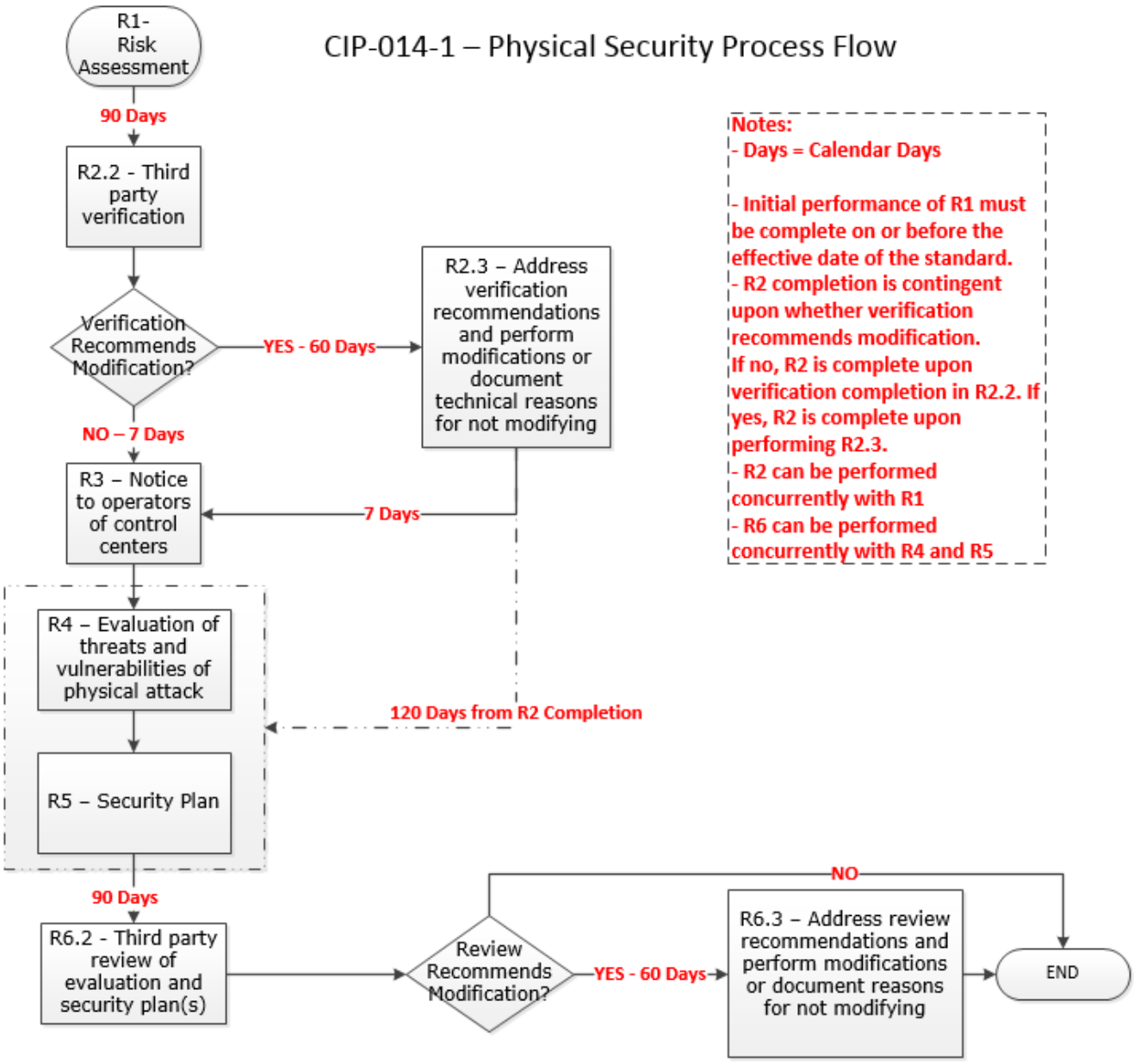
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
NO
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. A revised SAR was approved by the Standards Committee on December 9, 2014 to address the directives issued in FERC Order No. 802 issued on November 20, 2014, in Docket No. RD14-15-000, *Physical Security Reliability Standard*, 146 FERC ¶ 61,140 (2014). The appointed Physical Security Standard Drafting Team made the revisions to the standard.

Description of Current Draft

This is the first draft of the proposed Reliability Standard, and it is being posted for a 45-day comment and concurrent initial ballot period. This draft includes proposed revisions to address the directives issued in FERC Order No. 802.

Anticipated Actions	Anticipated Date
45-day Comment and Initial Ballot.	February-March, 2015
10-day Final Ballot.	April, 2015
BOT Adoption.	May, 2015
File with applicable Regulatory Authorities.	June, 2015

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-1

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-2.~~CIP-014-1 is effective the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In those jurisdictions where regulatory approval is not required, CIP-014-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 of its~~in the~~ March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through ~~widespread~~ instability, uncontrolled separation, or cascading failures. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

~~It~~ Requirement R1 also meets the ~~portion of the~~FERC directive ~~from paragraph 11~~ for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment ~~any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection~~).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

Rationale for Requirement R3:

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

Rationale for Requirement R4:

This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified

and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

Rationale for Requirement R5:

This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

Rationale for Requirement R6:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an	result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an	instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection	Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 Applicability

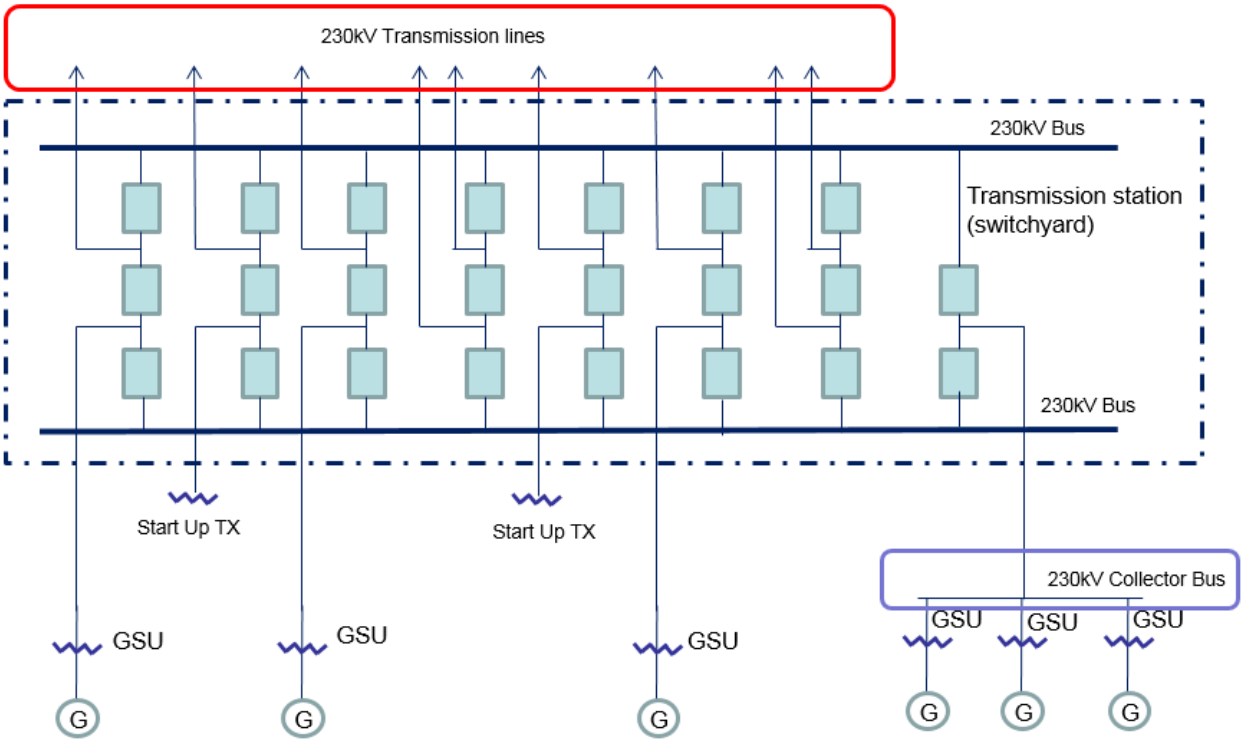
The purpose of Reliability Standard CIP-014~~-1~~ is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014~~-1~~ first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause ~~widespread~~ instability, uncontrolled separation, or Cascading within

an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014~~-1~~. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014~~-1~~, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014~~-1~~ when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014~~-1~~ standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. Regional

consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. ~~–~~Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in ~~widespread~~

instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both

Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.

- ASIS International Facilities Physical Security Measure Guideline.
- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

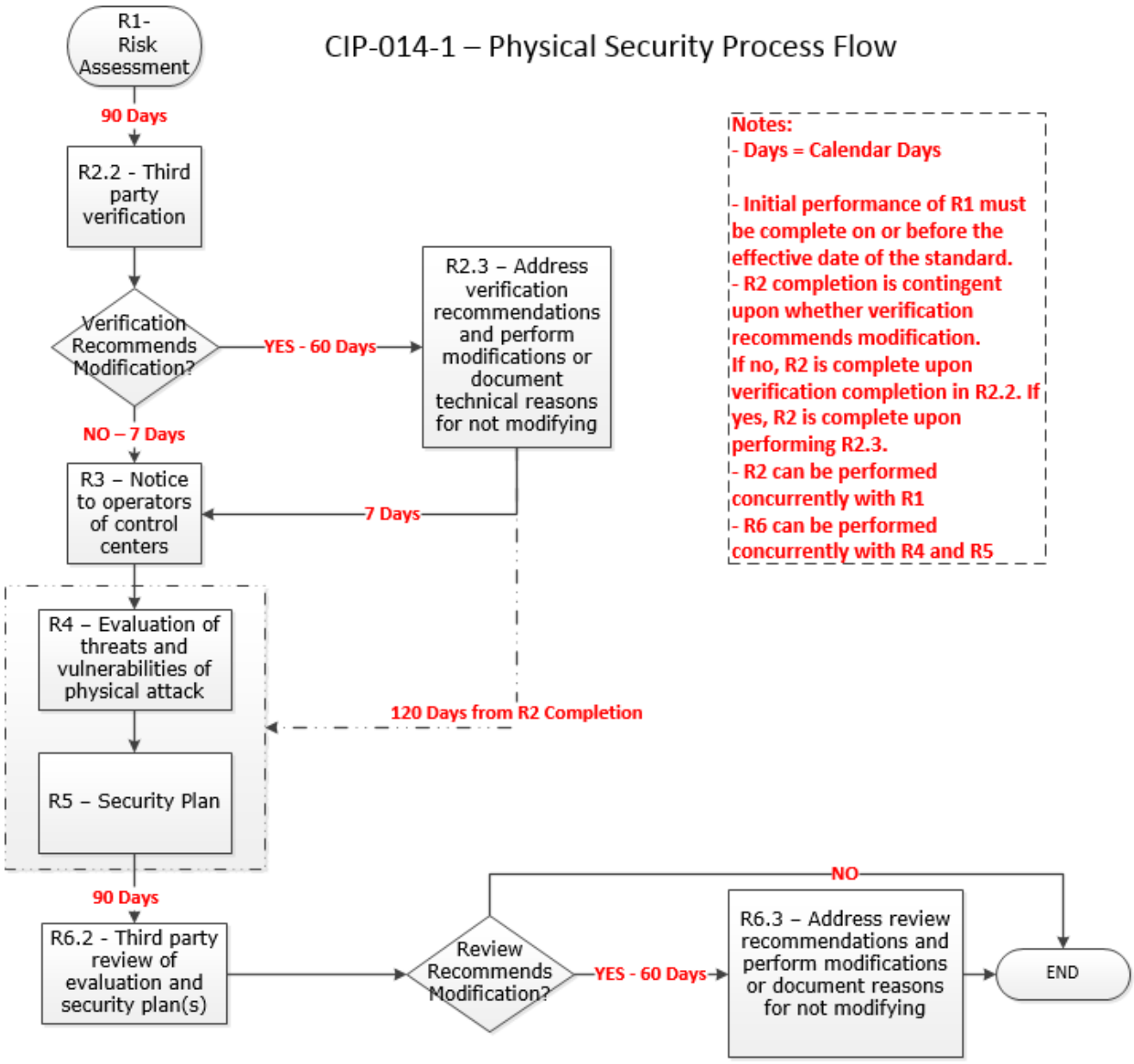
- *An entity or organization approved by the ERO.*

- *A governmental agency with physical security expertise.*

- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

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Implementation Plan

Physical Security Directives
CIP-014-2

Standards Involved

Approval:

- CIP-014-2 – Physical Security

Retirement:

- CIP-014-1 – Physical Security

Prerequisite Approvals:

N/A

Background

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

Effective Date

CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day after CIP-014-2 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction

Retirement of Existing Standards:

The existing standard, CIP-014-1, shall be retired at midnight of the day immediately prior to the effective date of CIP-014-2 in the particular jurisdiction in which the revised standard is becoming effective.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Transmission Operator

Implementation of CIP-014-1

All aspects of the Implementation Plan for CIP-014-1 will remain applicable to CIP-014-2 and are incorporated here by reference.

Cross References

The Implementation Plan for CIP-014-1 is available here.

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Unofficial Comment Form

Project 2014-04 Physical Security
CIP-014-2

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the draft CIP-014-2 Reliability Standard. The electronic comment form must be completed by **8 p.m. Eastern on April 9, 2015.**

If you have questions, contact Stephen Crutchfield (via email) or by telephone at (609) 651-9455.

The project page may be accessed here.

Background Information

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

FERC noted that incorporating the undefined term "widespread" in Reliability Standard CIP-014-1 introduces excessive uncertainty in identifying critical facilities under Requirement R1. As the Commission stated in the March 7 Order, only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1. The March 7 Order did not intend to suggest that the physical security Reliability Standards should address facilities that do not have a "critical impact on the operation of the interconnection." This understanding is, we believe, unintentionally absent in Requirement R1 because the requirement only deems a facility critical when, if rendered inoperable or damaged, it could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. The definition in Requirement R1 should not be dependent on how an applicable entity interprets the term "widespread" but instead should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1.

The Physical Security Standard Drafting Team (PSSDT) revised CIP-014-1, Physical Security, by removing the term "widespread" from the standard. This was done in the Purpose Statement, Background Section, Requirement R1, the Rationale for Requirement R1 as well as the Guidance and Technical Basis Section of the standard. Additionally, the PSSDT has added the following to the Rationale and guideline and Technical Basis for Requirement R1:

"The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact"

Additionally, the PSSDT revised the Rationale for Requirement R1 as follows:

> Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk).

You do not have to answer all questions below. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained. Due to the expected volume of comments, the SDT asks that commenters consider consolidating responses and endorsing comments provided by another.

Questions

1. The PSSDT has revised CIP-014-1, Physical Security, to address the directive from FERC to to remove the term "widespread" from Reliability Standard CIP-014-1. Do you agree with the proposed revisions to the standard contained in CIP-014-2 as summarized above? If not, please provide specific comments regarding the revisions and any suggestions for appropriate revisions.

   ☐ Yes
   ☐ No

   Comments:

Consideration of Issues and Directives

Project 2014-04 - Physical Security Directives

January 27, 2015

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 19. In addition to approving Reliability Standard CIP-014-1, the Commission adopts in part the NOPR proposal directing NERC to develop and submit modifications to the Reliability Standard concerning the use of the term "widespread" in Requirement R1. The Commission determines that the term "widespread" is unclear with respect to the obligations it imposes on applicable entities; how it would be implemented by applicable entities; and how it would be enforced. Accordingly, the Commission directs NERC, pursuant to FPA section 215(d)(5), to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. We direct that NERC submit a responsive	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	The Physical Security Standard Drafting Team (PSSDT) revised CIP-014-1, Physical Security, by removing the term "widespread" from the standard. This was done in the Purpose Statement, Background Section, Requirement R1, the Rationale for Requirement R1 as well as the Guidance and Technical Basis Section of the standard. Additionally, the PSSDT has added the following to the Rationale and guideline and Technical Basis for Requirement R1: "The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
modification within six months from the effective date of this final rule. Paragraph 35: Accordingly, pursuant to FPA section 215(d)(5), the Commission directs NERC to develop a modification to Reliability Standard CIP-014-1 that either removes the term "widespread" from Requirement R1 or, in the alternative, proposes changes that address the Commission's concerns. Further, we direct that NERC submit a responsive modification within six months from the effective date of this final rule. We recognize that certain entities commented on how NERC could modify Reliability Standard CIP-014-1 to address the Commission's stated concerns. However, we conclude that it is appropriate to allow NERC to develop and propose a modification in the first instance.		the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following: • Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6 • NERC EOP-004-2 reporting criteria • Area or magnitude of potential impact" Additionally, the PSSDT revised the Rationale for Requirement R1 as follows: "Requirement R1~~It~~ also meets the ~~portion of the~~ FERC directive ~~from paragraph 11~~ for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment) ~~any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an interconnection)~~."

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 21. With respect to the informational filings proposed in the NOPR, the Commission adopts the proposal to direct NERC to make an informational filing addressing whether Reliability Standard CIP-014-1 provides physical security for all "High Impact" control centers, as that term is defined in Reliability Standard CIP-002-5.1, necessary for the reliable operation of the Bulk-Power System. However, the Commission extends the deadline for that informational filing until two years following the effective date of Reliability Standard CIP-014-1. Paragraph 57. The Commission adopts the NOPR proposal and directs NERC to submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers. The Commission, however, modifies the NOPR proposal and extends the due date for the informational filing to two years following the effective date of Reliability Standard CIP-014-1.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1 and R2 with respect to "High Impact" control centers as that term is defined in Reliability Standard CIP-002-5.1 as that term is defined in Reliability Standard CIP-002-5.1. NERC will submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers within two years following the effective date of Reliability Standard CIP-014-1.

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 44. The Commission, instead, will focus its resources on carrying out compliance and enforcement activities to ensure that critical facilities are identified under Requirement R1. In its comments, NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1, R2 and R3 and will submit to the NERC Board of Trustees, a report three months following implementation of these Requirements concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC will also submit this report to Commission staff.

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Project 2014-04 - Physical Security Directives

Mapping Document

Background

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered	Removed the term "widespread" from Requirement R1	**R1.** Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]* **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that		inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]* **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.		Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.
R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with	Retained from previous version	**R2.** Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]* **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience. **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90		after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]* **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience. **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
calendar days following the completion of the Requirement R1 risk assessment. **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation: • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.		calendar days following the completion of the Requirement R1 risk assessment. **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation: • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.		**2.4.** Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.
R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the	Retained from previous version	**R3.** For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]* **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.		primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]* **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.
	Retained from previous version	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]* **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s); **4.2.** Prior history of attack on similar facilities taking into account the frequency,	Retained from previous version	**R4.** Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]* **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s); **4.2.** Prior history of attack on similar facilities taking into account the frequency,

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
geographic proximity, and severity of past physical security related events; and **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.		geographic proximity, and severity of past physical security related events; and **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.
R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and	Retained from previous version	**R5.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]* **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4. **5.2.** Law enforcement contact and coordination information. **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.		control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]* **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4. **5.2.** Law enforcement contact and coordination information. **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).		**5.4.** Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).
R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*	Retained from previous version	**R6.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: • An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. • An entity or organization approved by the ERO. • A governmental agency with physical security expertise. • An entity or organization with demonstrated law enforcement, government, or military physical security expertise.		**6.1.** Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: • An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. • An entity or organization approved by the ERO. • A governmental agency with physical security expertise. • An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5. **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:		**6.2.** The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5. **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
• Modify its evaluation or security plan(s) consistent with the recommendation; or • Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation. **6.4.** Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.		• Modify its evaluation or security plan(s) consistent with the recommendation; or • Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation. **6.4.** Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2014-04: Physical Security

VRF and VSL Justifications for CIP-014-2

VRF and VSL Justifications – CIP-014-1, R1	
Proposed VRF	High
NERC VRF Discussion	Initial and subsequent risk assessments identify Transmission stations or Transmission substations that need to be assessed for threats and vulnerabilities and potential physical security measures. Since this is a Requirement in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the risk assessment periodicity and the identification of the primary control center that has operational control of Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-002-5.1 R1, which deals with categorizing cyber systems, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date;

VRF and VSL Justifications – CIP-014-1, R1	
	OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.
Proposed Moderate VSL	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.
Proposed High VSL	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date;

VRF and VSL Justifications – CIP-014-1, R1	
	OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.
Proposed Severe VSL	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk

VRF and VSL Justifications – CIP-014-1, R1	
	assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if the risk assessment is not performed or if the risk assessment is not performed within required intervals.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit perform a risk assessment.

VRF and VSL Justifications – CIP-014-1, R2	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party verification of initial and subsequent risk assessments provides reinforcement that the risk assessment was performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party verification including entities that may perform the verification, provisions for adding or removing Transmission stations and/or Transmission substations, and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days following completion of Requirement R1;

VRF and VSL Justifications – CIP-014-1, R2	
	OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.
Proposed Moderate VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.
Proposed High VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by part 2.3.
Proposed Severe VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party

VRF and VSL Justifications – CIP-014-1, R2	
	verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party verification is not performed or if the verification is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to have an unaffiliated third party verification performed; or failing to perform the verification within prescribe timelines; or failing to implement procedures to protect information.

VRF and VSL Justifications – CIP-014-1, R2	
on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – CIP-014-1, R3	
Proposed VRF	Lower
NERC VRF Discussion	Notifying the Transmission Operator that it has operational control of a Transmission station or Transmission substation identified in Requirement R1 and verified in Requirement R2 is necessary so that the Transmission Operator may begin performance of subsequent physical security requirements for the primary control center. This is a requirement that is administrative in nature and in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. This justifies a Lower VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the notification of the Transmission Operator regarding the removal of a Transmission station or Transmission substation.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-4 R6, which deals with notifying other entities so that Confirmed Interchange may be implemented, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar

VRF and VSL Justifications – CIP-014-1, R3	
	days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.
Proposed Moderate VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.
Proposed High VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.
Proposed Severe VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1.

VRF and VSL Justifications – CIP-014-1, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if notification is not made subject to the conditions of the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to make the appropriate notification.

VRF and VSL Justifications – CIP-014-1, R4	
Proposed VRF	Medium
NERC VRF Discussion	Performing an evaluation of potential threats and vulnerabilities of a physical attack to each of respective Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the evaluation of potential threats and vulnerabilities of a physical attack to Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-007-5 R2, which deals with a patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – CIP-014-1, R4	
Proposed Moderate VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.
Proposed High VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.
Proposed Severe VSL	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failed to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R4	
Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failing to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R5	
Proposed VRF	High
NERC VRF Discussion	Development, implementation and execution of a documented physical security plan(s) that covers applicable Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the physical security plan for applicable Transmission stations, Transmission substations, or primary control centers.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-003-3 R4, which deals with implementing and documenting a program to identify, classify, and protect information associated with Critical Cyber Assets, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2;

VRF and VSL Justifications – CIP-014-1, R5	
	OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.
Proposed Moderate VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.
Proposed High VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.
Proposed Severe VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission

VRF and VSL Justifications – CIP-014-1, R5	
	station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include Parts 5.1 through 5.4 in the plan.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s) or if the responsible entity failed to include any of the Requirement Parts 5.1-5.4.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level	The VSL is assigned for a single instance of failing to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and

VRF and VSL Justifications – CIP-014-1, R5	
Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	primary control center(s) or failing to include any of the Requirement Parts 5.1-5.4.

VRF and VSL Justifications – CIP-014-1, R6	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party review of the threat evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 provides reinforcement that these requirements were performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party review including entities that may perform the review, timelines for completing the review and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days;

VRF and VSL Justifications – CIP-014-1, R6	
	OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.
Proposed Moderate VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.
Proposed High VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not and modify or document the reason for not modifying the security plan(s) as specified in Part 6.3.
Proposed Severe VSL	The Responsible Entity failed to have an unaffiliated third party

VRF and VSL Justifications – CIP-014-1, R6	
	review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.3.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party review is not performed or if the review is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R6	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to have an unaffiliated third party review performed; or failing to perform the review within prescribe timelines; or failing to implement procedures to protect information.

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Standards Announcement

Reminder

Project 2014-04 Physical Security
CIP-014-2

Initial Ballot and Non-binding Poll Open through April 9, 2015

Balloting and commenting for this project are in the Standards Balloting & Commenting System (SBS)

Now Available

An initial ballot for **CIP-014-2 – Physical Security** and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern, Thursday, April 9, 2015.**

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standard and associated VRFs and VSLs by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Stephen Crutchfield (via email), or at (609) 651-9455.

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Standards Announcement

Project 2014-04 Physical Security
CIP-014-2

Formal Comment Period Now Open through April 9, 2015
Ballot Pools Forming Now through March 23, 2015

Balloting and commenting for this project are in the Standards Balloting & Commenting System (SBS)

Now Available

A 45-day formal comment period for the **CIP-014-2 - Physical Security** standard is open through **8 p.m. Eastern, Thursday, April 9, 2015.**

SBS Login, Registration, Validation and Permissions

To **comment** in the SBS, you must have a contributor, voter, or proxy role.
To **join a ballot pool and vote** in the SBS, you must have a voter role.
To be a **proxy** and vote in the SBS, you must have a proxy role.

To register to become a proxy or voter in the SBS:

- Go to 'My User Profile'
- Select 'Click Here' to request additional permissions
- Select 'Voter' or 'Proxy Voter'

Instructions for Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Join the Ballot Pools

Note: If you had previously joined the ballot pools for CIP-014-1, you **must** join these ballot pools to cast a vote. Previous CIP-014-1 ballot pool members **have not** been carried over to these ballot pools.

Registered Ballot Body members may join the ballot pools here.

RSAW

The draft RSAW for the standard **CIP-014-2 - Physical Security** is posted on the project page. Submit comments regarding the draft RSAW to RSAWfeedback@nerc.net**.**

Next Steps

An initial ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 31 through April 9, 2015.**

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Stephen Crutchfield (via email), or by telephone at 609-651-9455.

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Standards Announcement

Project 2014-04 Physical Security
CIP-014-2

Formal Comment Period Now Open through April 9, 2015
Ballot Pools Forming Now through March 23, 2015

Balloting and commenting for this project are in the Standards Balloting & Commenting System (SBS)

Now Available

A 45-day formal comment period for the **CIP-014-2 - Physical Security** standard is open through **8 p.m. Eastern, Thursday, April 9, 2015.**

SBS Login, Registration, Validation and Permissions

To **comment** in the SBS, you must have a contributor, voter, or proxy role.
To **join a ballot pool and vote** in the SBS, you must have a voter role.
To be a **proxy** and vote in the SBS, you must have a proxy role.

To register to become a proxy or voter in the SBS:

- Go to 'My User Profile'
- Select 'Click Here' to request additional permissions
- Select 'Voter' or 'Proxy Voter'

Instructions for Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Join the Ballot Pools

Note: If you had previously joined the ballot pools for CIP-014-1, you **must** join these ballot pools to cast a vote. Previous CIP-014-1 ballot pool members **have not** been carried over to these ballot pools.

Registered Ballot Body members may join the ballot pools here.

RSAW

The draft RSAW for the standard **CIP-014-2 - Physical Security** is posted on the project page. Submit comments regarding the draft RSAW to RSAWfeedback@nerc.net**.**

Next Steps

An initial ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 31 through April 9, 2015.**

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Stephen Crutchfield (via email), or by telephone at 609-651-9455.

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Standards Announcement

Project 2014-04 Physical Security
CIP-014-2

Initial Ballot and Non-binding Poll Results

Now Available

A 45-day formal comment period and initial ballot for **CIP-014-2 – Physical Security** as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Thursday, April 9, 2015.**

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot and non-binding poll.

Ballot	Non-binding Poll
Quorum /Approval	Quorum/Supportive Opinions
88.33% / 89.95%	86.33% / 91.20%

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Stephen Crutchfield (via email), or at (609) 651-9455.

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/1)
Ballot Name: 2014-04 Physical Security CIP-014-2 IN 1 ST
Voting Start Date: 3/31/2015 12:01:00 AM
Voting End Date: 4/9/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 265
Total Ballot Pool: 300
Quorum: 88.33
Weighted Segment Value: 89.95

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	82	1	64	0.889	8	0.111	0	1	9
Segment: 2	9	0.5	4	0.4	1	0.1	0	2	2
Segment: 3	74	1	60	0.938	4	0.062	0	2	8
Segment: 4	21	1	16	0.889	2	0.111	0	2	1
Segment: 5	62	1	42	0.894	5	0.106	0	4	11
Segment: 6	40	1	36	0.947	2	0.053	0	0	2
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment:	2	0.1	1	0.1	0	0	0	0	1

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9									
Segment: 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	300	6.4	230	5.757	23	0.643	0	12	35

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	ATCO Electric	David Downey		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		None	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway	Terry Harbour		Affirmative	N/A

	Energy - MidAmerican Energy Co.				
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash	Candace Marshall	Affirmative	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy -	William Smith		Affirmative	N/A

	FirstEnergy Corporation				
1	Georgia Transmission Corporation	Jason Snodgrass	Matt Stryker	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	Daniel Gibson		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	Iberdrola - Central Maine Power Company	Joe Turano		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		None	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Oncor Electric Delivery	Rod Kinard		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Denise Lietz		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison		Negative	Third-Party Comments
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A

1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	United Illuminating Co.	Jonathan Appelbaum		Negative	Third-Party Comments
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		Affirmative	N/A
1	Xcel Energy, Inc.	Greg Pieper		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Abstain	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Negative	Third-Party Comments
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Matthew Goldberg	Michael Puscas	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Sarah Kist		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A

3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Central Hudson Gas & Electric Corp.	James Mccloskey		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Bill Hughes	Mary Downey	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit	Kent Kujala		Affirmative	N/A

	Edison Company				
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	Fayetteville Public Works Commission	Allen Wallace		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart		Affirmative	N/A
3	Florida Keys Electric Cooperative Assoc.	Tom Anthony		None	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Joshua Bach		None	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Greg LeGrave		Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A

3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northeast Utilities	Mark Kenny		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Terry Baker		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A

3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	We Energies - Wisconsin Electric Power Marketing	Jim Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A

4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Mary Downey	Affirmative	N/A
4	City of Winter Park	Mark Brown		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Abstain	N/A
4	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Christopher Plante		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A

4	Tacoma Public Utilities (Tacoma, WA)	Keith Morisette		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	brian robinson	Negative	Third-Party Comments
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Scott Takinen		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Kaleb Brimhall		Affirmative	N/A
5	Con Ed - Consolidated Edison	Brian O'Boyle		Affirmative	N/A

	Co. of New York				
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Golden Spread Electric Cooperative, Inc.	Chip Koloini		Abstain	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Brett Holland		Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Scott Johnson		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Liberty Electric Power LLC	Daniel Duff		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A

5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Bernard Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Christopher Wood		Affirmative	N/A
5	Public Utility District No. 1 of Douglas County	Curt Wilkins		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A

5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Negative	Comments Submitted
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	U.S. Army Corps of Engineers	Melissa Kurtz		None	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Negative	Comments Submitted
5	We Energies - Wisconsin Electric Power Co.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Randy Young		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A

6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Brenda Anderson		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern	Joe O'Brien		Affirmative	N/A

	Indiana Public Service Co.				
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Seattle City Light	Dennis Sismaet		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
7	Siemens - Siemens PTI	Frank McElvain		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts	Frederick Plett		Affirmative	N/A

	Attorney General				
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	National Association of Regulatory Utility Commissioners	Jerry Maio		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

BALLOT RESULTS

Ballot Name: 2014-04 Physical Security CIP-014-2 Non-Binding Poll IN 1 NB
Voting Start Date: 3/31/2015 12:01:00 AM
Voting End Date: 4/9/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 240
Total Ballot Pool: 278
Quorum: 86.33
Weighted Segment Value: 91.2

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	77	1	49	0.907	5	0.093	0	13	10
Segment: 2	9	0.4	3	0.3	1	0.1	0	2	3
Segment: 3	67	1	41	0.932	3	0.068	0	14	9
Segment: 4	18	1	13	1	0	0	0	4	1
Segment: 5	60	1	34	0.895	4	0.105	0	11	11
Segment: 6	36	1	26	0.929	2	0.071	0	6	2
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	2	0.1	1	0.1	0	0	0	0	1

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Segment: 10	6	0.4	3	0.3	1	0.1	0	2	0
Totals:	278	6.1	172	5.563	16	0.537	0	52	38

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	ATCO Electric	David Downey		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		None	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power	Donald Watkins		Affirmative	N/A

	Administration				
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash	Candace Marshall	Abstain	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission	Jason Snodgrass	Matt Stryker	Affirmative	N/A

	Corporation				
1	Great Plains Energy - Kansas City Power and Light Co.	Daniel Gibson		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		None	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A

1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Oncor Electric Delivery	Rod Kinard		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Denise Lietz		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A

1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison		Negative	Third-Party Comments
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		None	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A

2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Abstain	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Negative	Third-Party Comments
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Matthew Goldberg	Michael Puscas	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Sarah Kist		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy	Thomas Mielnik		Abstain	N/A

	Co.				
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	Fayetteville Public Works Commission	Allen Wallace		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart		Affirmative	N/A
3	Florida Keys Electric Cooperative Assoc.	Tom Anthony		None	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Joshua Bach		None	N/A

3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northeast Utilities	Mark Kenny		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power	Terry Baker		Abstain	N/A

	Authority				
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A

3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Winter Park	Mark Brown		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Abstain	N/A
4	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Christopher Plante		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Abstain	N/A

4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Keith Morisette		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	brian robinson	Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Scott Takinen		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Kaleb Brimhall		Affirmative	N/A

5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Golden Spread Electric Cooperative, Inc.	Chip Koloini		Abstain	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Brett Holland		Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Scott Johnson		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Liberty Electric Power LLC	Daniel Duff		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A

5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Bernard Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Christopher Wood		Abstain	N/A
5	Public Utility District No. 1 of Douglas County	Curt Wilkins		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A

5	Salt River Project	Kevin Nielsen		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Negative	Comments Submitted
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	U.S. Army Corps of Engineers	Melissa Kurtz		None	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Negative	Comments Submitted
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Randy Young		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Brenda Anderson		Affirmative	N/A

6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Seattle City Light	Dennis Sismaet		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
7	Siemens - Siemens PTI	Frank McElvain		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	National Association of Regulatory Utility Commissioners	Jerry Maio		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Previous 1 Next

Showing 1 to 278 of 278 entries

Comments Received Report

Survey Details

Name 2014-04 Physical Security

Description

Start Date 2/20/2015

End Date 4/10/2015

Associated Ballots

2014-04 Physical Security CIP-014-2 IN 1 ST

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
Randi Heise	Dominion - Dominion Resources, Inc.	5		Dominion - RCS	Larry Nash	Dominion Virginia Power	SERC	1
					Louis Slade	Dominion Resources, Inc.	SERC	6
					Connie Lowe	Dominion Resources, Inc.	RFC	3
					Randi Heise	Dominion Resources, Inc,	NPCC	5
Michael Lowman	Duke Energy	1,3,5,6	FRCC,SERC,RFC	Duke Ballot Body Members	Doug Hils	Duke Energy	RFC	1
					Lee Schuster	Duke Energy	FRCC	3
					Dale Goodwine	Duke Energy	SERC	5
					Greg Cecil	Duke Energy	RFC	6
Ben Li	Independent Electricity	2	NPCC	ISO/RTO Council	Charles Yeung	SPP	SPP	2

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
	System Operator			Standards Review Committee	Christina Bigelow	ERCOT	TRE	2
					Terry Bilke	MICO	MRO	2
					Mark Holman	PJM	RFC	2
					Greg Campoli	NYISO	NPCC	2
					Ali Miremadi	CAISO	WECC	2
					Ben Li	IESO	NPCC	2
Emily Rousseau	MRO	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
					Amy Casucelli	Xcel Energy	MRO	1,3,5,6
					Chuck Lawrence	American Transmission Company	MRO	1
					Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
					Dan Inman	Minnkota Power	MRO	1,3,5,6

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
						Cooperative, Inc		
					Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
					Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
					Jodi Jenson	Western Area Power Administration	MRO	1,6
					Larry Heckert	Alliant Energy	MRO	4
					Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
					Marie Knox	Midwest ISO Inc.	MRO	2
					Mike Brytowski	Great River Energy	MRO	1,3,5,6
					Randi Nyholm	Minnesota Power	MRO	1,5
					Scott Nickels	Rochester Public Utilities	MRO	4

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
					Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
					Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
					Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Paul Haase	Seattle City Light	1,3,4,5,6	WECC	Seattle City Light	Pawel Krupa	Seattle City Light	WECC	1
					Dana Wheelock	Seattle City Light	WECC	3
					Hao Li	Seattle City Light	WECC	4
					Mike Haynes	Seattle City Light	WECC	5
					Dennis Sismaet	Seattle City Light	WECC	6
Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	SPP	2

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
					John Allen	City Utilities of Springfield	SPP	1,4
					Hollie Baker	Oklahoma Gas and Electric Company	SPP	1,3,5,6
					Mike Buyce	City Utilities of Springfield	SPP	1,4
					J.Scott Williams	City Utilities of Springfield	SPP	1,4
					Louis Guidry	Cleco Power LLC	SPP	1,3,5,6
					Jonathan Hayes	Southwest Power Pool Inc.	SPP	2
					Robert Hirchak	Cleco Corporation	SPP	1,3,5,6
					James Simms	Cleco Power LLC	SPP	1,3,5,6
					Jason Smith	Southwest Power Pool Inc	SPP	2
					Don Schmit	Nebraska Public Power District	MRO	1,3,5

Survey Questions

See the Unofficial Comment Form on the Project Page for additional background information.

If you would like to bypass taking the survey, click the radio button and scroll down to submit the survey.

This will allow you to view Social Survey and agree / disagree with an already posted comment using the "thumbs up / thumbs down" feature.

Submitting a "thumbs up / thumbs down" on another entity's comment enables a negative vote to count in the calculation of consensus.

I want to bypass taking the survey

1. The PSSDT has revised CIP-014-1, Physical Security, to address the directive from FERC to to remove the term "widespread" from Reliability Standard CIP-014-1.

Do you agree with the proposed revisions to the standard contained in CIP-014-2 as summarized above? If not, please provide specific comments regarding the revisions and any suggestions for appropriate revisions.

Yes

No

Responses By Question

See the Unofficial Comment Form on the Project Page for additional background information.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Frank McElvain - Siemens - Siemens PTI - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amanda Owen - AEP - NA - Not Applicable - TRE,SPP,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Allen Wallace - Fayetteville Public Works Commission - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dana Wheelock - Seattle City Light - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Shanahan - National Grid USA - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Stephen Pogue - M and A Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Romel Aquino - Edison International - Southern California Edison Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Romel Aquino - Edison International - Southern California Edison Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Jastram - Portland General Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Great River Energy - 1 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Turner - APS - Arizona Public Service Co. - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Catherine Wesley - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry Bllke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Reynolds - Southwest Power Pool Regional Entity - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Lowman - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg LeGrave - Integrys Energy Group, Inc. - Wisconsin Public Service Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Mertz - PNM Resources - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris de Graffenried - Con Ed - Consolidated Edison Co. of New York - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kent Kujala - DTE Energy - Detroit Edison Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Herring - DTE Energy - Detroit Edison Company - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Herring - DTE Energy - Detroit Edison Company - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Warren Cross - ACES Power Marketing - 6 - MRO,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - ATCO Electric - 1 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes:	0	

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Steve Johnson - Western Area Power Administration - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael DeLoach - AEP - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Jastram - Portland General Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Fuchsia Davis - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Teresa Cantwell - Lower Colorado River Authority - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

If you would like to bypass taking the survey, click the radio button and scroll down to submit the survey.

This will allow you to view Social Survey and agree / disagree with an already posted comment using the "thumbs up / thumbs down" feature.

Submitting a "thumbs up / thumbs down" on another entity's comment enables a negative vote to count in

the calculation of consensus.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 - TRE

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Frank McElvain - Siemens - Siemens PTI - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amanda Owen - AEP - NA - Not Applicable - TRE,SPP,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Allen Wallace - Fayetteville Public Works Commission - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dana Wheelock - Seattle City Light - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Shanahan - National Grid USA - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Stephen Pogue - M and A Electric Power Cooperative - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Romel Aquino - Edison International - Southern California Edison Company - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Romel Aquino - Edison International - Southern California Edison Company - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Jastram - Portland General Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Great River Energy - 1 - MRO

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Turner - APS - Arizona Public Service Co. - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Catherine Wesley - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry Bllke - Midcontinent ISO, Inc. - 2 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Reynolds - Southwest Power Pool Regional Entity - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Lowman - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg LeGrave - Integrys Energy Group, Inc. - Wisconsin Public Service Corporation - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Mertz - PNM Resources - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott

Dislikes: 0

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris de Graffenried - Con Ed - Consolidated Edison Co. of New York - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kent Kujala - DTE Energy - Detroit Edison Company - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Herring - DTE Energy - Detroit Edison Company - 4 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Herring - DTE Energy - Detroit Edison Company - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Warren Cross - ACES Power Marketing - 6 - MRO,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - ATCO Electric - 1 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steve Johnson - Western Area Power Administration - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael DeLoach - AEP - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Jastram - Portland General Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Fuchsia Davis - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Teresa Cantwell - Lower Colorado River Authority - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

1. The PSSDT has revised CIP-014-1, Physical Security, to address the directive from FERC to to remove the term "widespread" from Reliability Standard CIP-014-1.

Do you agree with the proposed revisions to the standard contained in CIP-014-2 as summarized above? If not, please provide specific comments regarding the revisions and any suggestions for appropriate revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Frank McElvain - Siemens - Siemens PTI - 7 -

Selected Answer: No

Answer Comment:

The removal of widespread is ok, but there is a larger problem.

The CIP-014-2 Standard is missing some fundamental elements in R1 and R2 to assure reliability if the contemplated contingency were to actually occur, and to be consistent with other standards. To approve the standard as currently written creates inconsistencies among the entire family of reliability standards.

Station or substation damage would likely include equipment that could currently take as long as 16 months to replace. With such a lengthy period of time in which a damaged station could be out-of-service, the standard needs to explicitly require determination of limits under the system's new normal condition, and to accommodate more probable N-1 contingencies.

CIP-014 should also be consistent with other NERC standards, such as TOP-004, which requires operation within known operating limits, and preparing for the next contingency within 30 minutes. It is unrealistic to expect these limits to be determined in real-time after a substation-out event as contemplated in CIP-014.

The level of study performed in preparation for a loss of a substation (or station) can vary from one organization to another and not every system limit needs to be determined in advance. However, minimally, CIP-014 should require that generating units are confirmed to remain stable for the next N-1 contingency, that current IROLs are not degraded in the new normal condition, and that generation contingency reserves remain adequate.

Document Name:

Likes: 0

Dislikes: 0

Amanda Owen - AEP - NA - Not Applicable - TRE,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer: No

Answer Comment:

My comment addresses the proposed Implementation Plan. While accepting that the change in the proposed standard is minor with respect to the currently approved version, it would be advisable to have an effective date that gives a more reasonable time, e.g. 30 days after the applicable date instead of the proposed day immediately after approval or day after the effective date of Version 1. This in order to permit relevant entities to do any necessary administrative work required for implementation.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: Yes

Answer Comment:

Exelon agrees with the SDT proposal to remove the term "widespread" from Reliability Standard CIP-014-1. With that change we believe the standard is responsive to the directive and supportive of reliability.

We do not agree that an alternative modification is necessary to meet the concern raised in the Directive. Alternative modifications are likely to delay implementation and lead to new revisions requiring further clarification with no appreciable gain in reliability.

Document Name:

Likes: 0

Dislikes: 0

Allen Wallace - Fayetteville Public Works Commission - 3 -

Selected Answer: No

Answer Comment:

The concern with removing the term "widespread" is that it potentially imposes the requirements of the standard upon smaller

substations and entities that could have minimal impact on the BES. While I would prefer a more quantifiable determinant of applicability (customers affected, miles of transmission, load or generation lost, etc.) I believe that widespread is better than no discriminant at all.

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dana Wheelock - Seattle City Light - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

With the word “widespread” removed, R1 is stating that if rendering a station inoperable results in any instability (large or small), the station should be declared critical. Depending on the severity of an instability, there may or may not be an impact on the operation of the interconnection. We are proposing the following modification to R1 to make it clearer in terms of reliability impact on the “Interconnection” in which the assessed facilities lie.

“Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in a critical impact on the operation of the interconnected (or neighboring) power system by causing instability, uncontrolled separation, or Cascading within an Interconnection.”

Document Name:

Likes: 1 Herb Schrayshuen, 2, Schrayshuen Herb

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Shanahan - National Grid USA - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Stephen Pogue - M and A Electric Power Cooperative - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Romel Aquino - Edison International - Southern California Edison Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Romel Aquino - Edison International - Southern California Edison Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Jastram - Portland General Electric Co. - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Seattle City Light supports the proposed revisions expressed in draft CIP-014-2 to remove the undefined term "widespread" and votes affirmative. In particular Seattle supports the new guidance language added to the Standard and supporting documents to explain what is meant by the term "widespread" that would no longer be included in the Standard.

Seattle, however, would support the proposed draft further if the term "widespread" was not simply removed from CIP-014-2 but replaced everywhere by "critical." Although "critical" is no more defined than "widespread," the term is the exact word used by FERC in its Order requesting removal of "widespread" and relates directly to FERC and NERC guidance on the matter.

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Great River Energy - 1 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Turner - APS - Arizona Public Service Co. - 1,3,5,6 - WECC

Selected Answer:	No

Answer Comment:

All though we agree the with the removal of the word “widespread” from the standard, we feel leaving the word “instability” in the standard still makes it vague and inconsistent. We suggest that both word “widespread” and “instability” be taken out to read R1 as follows:

“… The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in uncontrolled separation, or Cascading within an Interconnection.

The criticality of a facility to an interconnection is determined by its impact and not by instability. Instability is a symptom and not the final consequence. There are various types of instabilities and with consequence varying from a small 10 W generation tripping to an interconnection braking up and many things in between. There are many other symptoms which are also indicators of cascading such as excessive overload, very low voltages etc. but none of them are called out. So why leave instability in there?

The above proposed wording preserves all of the impact without dwelling on symptoms.

Document Name:

Likes:	0
Dislikes:	0

Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer: No

Answer Comment:

FERC Order No. 802 states on page 18: "The definition in Requirement R1 should not be dependent on how an applicable entity interprets the term "widespread" but instead should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1."

Rather than merely remove the word "widespread," NERC could better comply with the FERC order to provide clarity with a simple rearrangement of terms.

By reordering R1 from:

…if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

To:

…if rendered inoperable or damaged could result in uncontrolled separation or Cascading within, or the instability of, an Interconnection.

This reorganization maintains all the wording of R1 without introducing any undefined or subjective terms, but more clearly ties the term "instability" to "Interconnection." This better reflects the FERC intention of affecting an interconnection, and by changing the intervening modifier between the terms "instability" and "Interconnection" from "within" to "of" addresses the industry concern that R1, as left without the term "widespread," could be interpreted as applying to localized areas of instability

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

ERCOT supports and references the comments to be filed by the ISO/RTO Council Standards Review Committee.

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Catherine Wesley - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

While we agree that the revision addresses the directive, it's unfortunate that this required change muddles common understanding of NERC's terms and definitions.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Reynolds - Southwest Power Pool Regional Entity - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Lowman - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Duke Energy would like to thank the SDT for their efforts on this project. In addition, we agree with the changes made by the SDT.

Document Name:

Likes: 0

Dislikes: 0

Greg LeGrave - Integrys Energy Group, Inc. - Wisconsin Public Service Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

NSRF's concerns with the proposed changes to CIP-014-2 standard.

1. Removal of the term , "widespread", from R1 without replacement text in R1 - The qualifying concept of "widespread" was removed from R1 without replacing it with alternate text to address the Commission's concerns. This approach makes the text in R1 even less defined than the original CIP-014-1 text. For example, the modified text offers no criteria to define the degree of reliability impacts due to instability or uncontrolled separation that would qualify a substation. This approach would allow applicable entites and regulators to interpret even minor or the R1 text to expect a substation to be qualified by local or minor reliability impacts as qualifying a substation. Addressing the Commission's concerns by relegating criteria text to the Rationale for R1, rather than including criteria text in R1, allows the text to be disregarded because the rationale will be removed when the standard is finalized. Addressing the Commission's concerns by relegating text to to the Guidance and Technical Basis section, rather than including text in R1, allows the text to be disregarded because, not being part of R1, the the application of guidance text may be a judgement call. Our concern stems from FERC Order 693, section 253, which states that ". . . compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts . . .". Each requirement must be clearly written for entities to follow. Any wording contained in a Guidance and Technical document is just that, wording. The words of "the Requirements within a standard define what an entity must do to be compliant".

Alternate text for R1 to replace2. Limiting the applicability of the term, “widespread””, to just instability – We interpret the qualification that the widespread reliability impact duerefers to “all three qualifying conditions – instability”, “, uncontrolled separation” and “Cascading, not to just instability alone.

3. Insufficient Use of NERC-Defined Terms - Alternate text for “widespread” should incorporatebe added to Requirement R1 and should make as much use of NERC defined-terms and concepts as much as possible. The NERC-defined term of “Adverse Reliability Impact” is used in Criterion 2.3 from Attachment 1 of the CIP-002-5.1 standard andFor example, the NERC-defined concept of “Interconnection Reliability Operating Limit” (IROL) is used in Criterion 2.9 from Attachment 1 of the CIP-002-5.1 standard. The FAC-010-2 standard already allows Planning Coordinators (PCs) to establishdefine criteria and methodology for establishing planning horizon IROLs that are appropriate for the PC’s area and the Interconnection where the limit will be applied.

Based on the preceding comments, 4. Clarification of the term, Interconnection – We interpret that the use of capitalized word “Interconnection” within the Purpose, R1, R1.1 bullet 1 and 2, and associated VSLs refers to any of the Eastern, Western, ERCOT or Quebec Interconnections, not a regional Balancing Authority interconnection or regional Independent System Operator interconnection.

NSRF suggests **recommends the following wording changes to address the above concerns:**

For Requirement R1, we suggest that the term, “widespread” in R1 be replaced with text like, “. . . if rendered inoperable or damaged could result an Adverse Reliability Impact on the BES within an Interconnection due to instability, uncontrolled separation, or Cascading” or “. .. . if rendered inoperable or damaged could result in the violation of one or more Interconnection Reliability Operation Limits (IROLs) within an Interconnection due to

instability, uncontrolled separation or Cascading within, or instability of, an Interconnection".

Also based on the preceding comments, ATC suggests revising the wording of the draft text in **For the R1 Rationale and** in the **Guidance and Technical Basis** section. ATC proposes that the wording near the end**Section**, we suggest the following modifications:

- {C}· Replace the wording of "The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the clarification text be simplified to focusfollowing: Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6; NERC EOP-004-2 reporting criteria; Area or magnitude of potential impact" with text that focuses on the concept on Adverse Reliability Impact or IROLs with language like, "The Transmission Owner should derive the criteria for the R1 risk assessment from the criteria used in the Adverse Reliability Impact definition or the criteria used to establish planning horizon IROLs as inper Requirement R3 of the NERC FAC-010-2 reliability standardReliability Standard."
- Add clarification regarding the four kinds of instability that should be considered with wording like, "The consideration of instability should include all four kinds of instability - steady state voltage instability, steady state angular instability, dynamic voltage instability, and dynamic angular instability."

Document Name:

Likes: 3 Nebraska Public Power District, 5, Schmit Don
Nebraska Public Power District, 3, Eddleman Tony
Nebraska Public Power District, 1, Cawley Jamison

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

Although we agree with removal of the term “widespread” from the standard, we do not find the supporting justification provided in the Rationale for R1 and/or the Guidelines and Technical Basis for R1 to be adequate and/or convincing. Specifically, we do not find the three proposed criteria for critical impact as particularly instructive to help identify which instability – out of the potentially several instabilities seen in the transmission analyses performed for R1 – would qualify as having a critical impact on the operation of the interconnection. Without a clear technical guidance on what are the attributes (quantitative and qualitative) of a “critical impact” instability” – that is, only an instability that has a critical impact on the operation of the interconnection, as stated in the March 7, 2014 Order – we do not see how the “excessive uncertainty in identifying critical facilities under R1” due to the undefined term “widespread” has been effectively addressed. Deletion of “widespread” without replacing it with adequately clear technical guidance on what constitutes a “critical impact instability” for an interconnection has only displaced the excessive uncertainty concern of FERC from “stability” to “critical impact” – it has not resolved it.

Since at least two of the three proposed criteria for critical impact puts the onus on the Transmission Owner (or its Transmission Planner) to determine (quantify) the “area or magnitude of potential impact” or determine how to identify “System instability” per R6 in TPL-001-4, this approach is prone to result in “critical impact” criteria that differ widely among the numerous Transmission Owners within each of the three Interconnections. This outcome would be incompatible and inconsistent with FERC’s stated guidance in the March 7, 2014 Order – and reiterated in the November 20, 2014 Order – that “***only*** an instability” that has a “critical impact on the operation ***of the interconnection***” (emphasis added) warrants finding that the facility resulting in the [critical interconnection impact] instability is deemed critical under Requirement R1.

We suggest the following two alternatives to address the above concerns:

1) Option 1: Enhance the technical guidance to provide a common Interconnection-wide criterion for what constitutes "critical impact" instability in the Interconnection. This would conceivably be different for each of the three Interconnections, resulting in three "critical impact" instability criteria. We note that this approach would be similar to what was adopted for the Order 754 stability studies/analyses. As such, we recommend using "Table C – Performance Measures" in the NERC Order 754 Data Request document as a good paradigm for developing an Interconnection-wide "critical impact" instability criteria.

2) Option 2: Modify Requirement R1 to recognize that only an instability that results in Cascading or uncontrolled separation within an Interconnection qualifies as one that has a "critical impact on the operation of the Interconnection". This approach implicitly acknowledges that all other instabilities have a limited (local) impact and therefore do not result in widespread instability, and widespread instability is synonymous with Cascading or uncontrolled separation. The following change in R1 and part 1.1 is suggested: "….could result in Cascading or uncontrolled separation within an Interconnection caused by (voltage or angular) instability and/or successive failures of overloaded Facilties."

Aside from the above, we suggest that the following compound sentence in the Rationale as well as Technical Basis be simplified and restructured to remove the existing contextual ambiguities that make comprehending its intent very difficult.

"The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or

damaged."

Further, we question if this sentence even belongs in the Rationale – it is hard to see how this provides a justification for Requirement R1. In fact, saying that "The requirement is not to require identification of…" appears to contradict the intent of the following verbiage in R1 "… transmission analyses designed to identify the…".

Lastly, it appears that the changes made in the following paragraph in the Rationale for R1 have inadvertently resulted in an incomplete/incoherent sentence within the parenthesis.

[It] **Requirement R1** also meets the [portion of the] **FERC** directive [from paragraph 11] for periodic reevaluation **of the risk assessment** by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment [any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection]).

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Selected Answer: No

Answer Comment:

With the word “widespread” removed, Requirement R1 implies that if and when a station becomes inoperable and a potential threat for instability (large or small), uncontrolled separation or cascading, the station should be declared critical. Depending on the severity of an instability, there may or may not be any adverse impact on the operation of the interconnection. For example, if a station in a pocket or remote area should become inoperable and a potential threat for instability, it may not create any adverse impact on interconnected operations. Hence, to capture the intent of the requirement such that it addresses facilities that can impact interconnected operations, suggest modifying R1 as follows (see words underlined and in bold):

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered

inoperable or damaged could result in **a critical impact on the operation of the interconnected power system by causing** instability, uncontrolled separation, or Cascading within an Interconnection.

For the Rationale Box for R1, we suggest replacing “among other criteria” with “for example.” This wording clarifies that the examples given are merely examples and not the only options for determining critical impact.

“[…] the Transmission Owner may determine the criteria for critical impact by considering, **for example**, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact”

In paragraph 6 of the FERC Docket No. RD14-6-000, “interconnection” is lower case. Should “interconnection” as used in the standard’s Rationale for Requirement R1 and in the Guidelines and Technical Basis on page 31 be upper or lower case?

To make the wording of the Rationale for Requirement R1 consistent with the wording in RD14-6-000, suggest rewording the second sentence to read”…applicable Transmission Owner determines through objective analysis, technical expertise, and experienced judgment…”R6 Severe VSL: “The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under

	Requirement R5 but failed to implement procedures for protecting information per Part 6.3" should read "per Part 6.4".	
Document Name:		
Likes:	2	Con Ed - Consolidated Edison Co. of New York, 1,3,5,6, Dash Kelly Con Ed - Consolidated Edison Co. of New York, 1, de Graffenried Chris
Dislikes:	0	

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Mertz - PNM Resources - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer: No

Answer Comment:

Removing "widespread" from criteria will leave the Reliability Standard open to "local" impact assessments by the audit teams, which could have exponential implications even for small municipal utilities. Removing the term "widespread" opens the scope of the standard to unlimited interpretation. The term "widespread" has been commonly and generally used since the mandatory and effective date of the NERC Reliability Standards to exclude such common occurrences as a storm moving through the area (daily during the summer in Florida), causing damage up to and including

some transmission outages. Would a lightning strike on a bulk power substation causing it to operate be termed instability under the Reliability Standard or would the lightning strike also have to cause the connecting transmission lines to operate? Therefore, does removal of the word "widespread" for consideration of instability mean that every bulk power facility outage, for whatever reason is now in violation of instability? There has to be some degree of limiting language to prevent the unintended spiral that removal of the word "widespread" will cause. Entities are familiar with and understand the use of the term "widespread". Removing this modifier from the scope of assessment will require extensive instruction and scenario analysis to make the scope of the assessment clear.

Document Name:

Likes:	2	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott Tallahassee Electric (City of Tallahassee, FL), 5, Webb Karen
Dislikes:	0	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0

Dislikes: 0

Chris de Graffenried - Con Ed - Consolidated Edison Co. of New York - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karen Webb - Tallahassee Electric (City of Tallahassee, FL) - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kent Kujala - DTE Energy - Detroit Edison Company - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Herring - DTE Energy - Detroit Edison Company - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Herring - DTE Energy - Detroit Edison Company - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Warren Cross - ACES Power Marketing - 6 - MRO,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

1. The removal of the undefined term of “widespread” from R1 should have alternate text to address the Commission’s concern(s) and to provide industry with clarity to the applicability of transmission facilities. While we understand the drafting team’s response to FERC’s directive to remove “widespread,” this language should be modified to make clear that a facility that has a

critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1. This blanket removal of 'widespread' from the requirements makes the text in R1 even more vague and subjective than the original CIP-014-1 language that is subject to interpretation and may result in a standard that is not auditable. By removing the word widespread, there is no clear delineation of reliability impact(s) due to instability or uncontrolled separation that would qualify a substation. This language change will cause inconsistent implementation across the regions and Transmission Planners or Planning Coordinators. Furthermore, given the cost implications on a possible Transmission Owner, more clarity and certainty of scope is needed.

2. Adding to the Rationale and Guideline and Technical Basis for Requirement R1 does not address the FERC Directive. The Rationale section while assisting industry to better understand the intention of the PSSDT is not enforceable and will result in an inconsistent R1 implementation across the regions.

3. The PSSDT should refer to NERC defined-terms and concepts, where appropriate. To add clarity to 'widespread,' the PSSDT should consider the NERC defined terms of "Adverse Reliability Impact" (Criterion 2.3 from Attachment 1 of the CIP-002-5.1), "Interconnection Reliability Operating Limit" (Criterion 2.9 from Attachment 1 of the CIP-002-5.1), and the FAC-010-2 standard that is in place to assist Planning Coordinators (PC) to establish planning horizon IROLs that are appropriate for the PC's area and the Interconnections.

4. Thank you for time, attention and consideration regarding these CIP-014-2 comments.

Document Name:

Likes: 0

Dislikes: 0

Dan Bamber - ATCO Electric - 1 - WECC

Selected Answer: Yes

Answer Comment:

Agree that removing the term widespread removes some subjectivity, however additional clarity on what is meant by the term "instability" would be beneficial in helping entities determine the appropriate critiera to be applied, as part of their risk assessment, in the identification of facilities in-scope to this standard.

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer: Yes

Answer Comment:

With the deletion of the term "widespread" from CIP-014, the TO

must *determine* whether instability, uncontrolled separation, or Cascading within an Interconnection could occur if the station was damaged or rendered inoperable. For jointly-owned facilities, i.e., two or more TOs at a Transmission station or Transmission substation, the Standard states the following on page 30 of 39:

"On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards."

In order to delegate responsibility to a single TO at a jointly-owned facility to make the above cited determination and the remaining Requirements in the Standard, Seminole Electric has the following questions:

(1) Can a Coordinated Functional Registration agreement (CFR), Joint Registration Organization agreement (JRO), or Memo of Understanding (MOU) be drafted on a station-by-station basis between parties? Seminole Electric is unaware whether CFRs and JROs can be developed and approved by NERC on a station-by-station basis and requests more information on this issue.

(2) In delegating responsibility for the Requirements in jointly-owned facilities under CIP-014-2, can an MOU be a sufficient mechanism to delegate authority if drafted sufficiently, or does the drafting team reason that ultimately a CFR or JRO must be executed between the co-owners (multiple TOs) at a station? Seminole Electric has been told that MOUs may be ineffective in delegating responsibility for the Requirements for jointly-owned facilities and that CFRs and JROs should be executed instead.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: Yes

Answer Comment:

Hydro One Networks Inc. supports the comments advanced by the NPCC RSC.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Hydro-Quebec TransEnergie supports the comments from NPCC-RSC

Document Name:

Likes: 0

Dislikes: 0

Steve Johnson - Western Area Power Administration - 1 -

Selected Answer: No

Answer Comment:

Western Area Power Administration supports the Bureau of Reclamation comments regarding the removal of "widespread". Specifically, we request the adoption of language referring to TPL-001-4 R6 for consistency.

Document Name:

Likes: 0

Dislikes: 0

Michael DeLoach - AEP - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Jastram - Portland General Electric Co. - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The group has a concern in reference to the removal of the term 'widespread' in that removing it doesn't provide any boundries to the scope of the instability or cascading outages. With that being said, this can lead to continued inconsistency throughout the industry. We understand that the Commission has a large concern about the term 'widespread' being in the doucmenation and the group would like to propose alternative language stated as followed: "instability uncontrolled separation or cascasding that would cause or affect an Operational IROL within the Interrconnection".

The group also has a concern pertaining to CIP-014 in reference to a Transmission Owner completing their assessment (which is due on or before October 15, 2015) more than 90 days before October 1. There is some confusion on when the verification would be completed (if the assessment was finished June 1). Does the Transmission Owner have 90 days from October 1 or 90 days from June 1? This would be with the assumption that the effective date is October 1. We would like the drafting team to provide more clarity in reference to Requirement R2.2 addressing this issue.

We have a concern about Requirement R4 and its timeline requirement. In the standard's Rationale Box for R4 (second paragraph), it states "Requirement R4 doesn't explicitly states when the evaluation has to be completed" however, Requirement R5 development of a security plan(s) depend on this information. We would like for the SDT to provide more detailed information on when the evaluation needs to be completed.

First line of the first paragraph of Requirement R3…. Page 9. The term ‘control center’ should be capitalized as its shown the Glossary of Terms. Additionally, this applicable for the last sentence of the paragraph.

First line of the first paragraph of Requirement R5…. Page 11. The term ‘control center’ should be capitalized as its shown the Glossary of Terms.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment:

The Bureau of Reclamation (Reclamation) does not agree with removing the term “widespread” from R1 without adding clarifying language in the text of the standard. This approach makes the text in R1 even less defined than the original CIP-014-1 text because it offers no criteria of what degree of reliability impacts due to instability or uncontrolled separation is appropriate to determine facilities identified under R1. This approach could cause a much broader range of facilities to come within the scope of the standard by allow interpretations that even minor or local reliability impacts result in some degree of “instability… within an interconnection.” Reclamation is concerned that the removal of the term "widespread" could expand the standard to include remote facilities that if lost could impact relatively small and isolated load pockets. Reclamation suggests that the drafting team include a

footnote referencing TPL-001-4 R6 criteria, reference other specific criteria like facilities affecting IROLs, or at least incorporate FERC's language "has a critical impact on the operation of the interconnection" into the language of R1. In the alternative, the drafting team could reference a specific area or magnitude of potential impact. Unlike the rationale statement, clarifying requirement language or a footnote would be an enforceable component the standard if approved by FERC. The clarifying language would ensure that the scope of facilities identified under R1 would not be dramatically broadened with the removal of the term "widespread."

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer: No

Answer Comment:

I am voting NO because I believe the Standard should be very specific as to what constitutes "damaged", if it is not equal to being "inoperable", as used in the Standard. Also, the Standard needs to be very specific about the method of "transmission analysis" for rendering the station "inoperable", such as complete loss of the station resulting in a three phase fault on the station bus, etc.. The Standard is very specific and clear as how to determine which facilities need to be analyzed (i.e., those exceeding an aggregate weighted value of 3000 as specified in Section 4.1.1.2), and it needs to be just as specific in defining "damaged" and the method of "transmission analysis".

Thank you.

Sincerely,

Spencer Tacke, MID

Document Name:

Likes: 0

Dislikes: 0

Fuchsia Davis - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Error: Subreport could not be shown.

Selected Answer:	No
Answer Comment:	With the removal of the term “widespread,” Requirement R1 implies that, if and when a station becomes inoperable and a potential threat for instability (large or small), uncontrolled separation or Cascading, the station should be declared critical. However, whether there is an adverse impact on the “operation of the interconnection” depends on the severity of an instability. In particular, a station or substation may create local instability, but there may or may not have an adverse or critical impact on the “operation of the Interconnection.” For example, if a station in a pocket or remote area should become inoperable and a potential threat for instability, it may create local instability, but such local instability may not impact the operation of the interconnected system in any way. Hence, to declare such a station as “critical” would defeat the purpose of focusing security operations on those stations and substations that have a “critical impact on the operation of the Interconnection.” The SRC appreciates that the Standard Drafting Team attempted to provide additional criteria to determine the criticality of impact by provding some guidance in the rationale section for Requirement R1. However, the SRC respectfully suggests that there is a potential that such guidance may result in diverse criteria regarding criticality, which would, in turn, result in substantially different determinations of criticality across and within the Interconnections. It may also create unintended complications regarding compliance with and activities performed under other reliability standards. Hence, given the interconnected nature of the grid and the reliability standards with which Transmission Operators and Owners must comply and to ensure that the requirement effectively conveys the intent to address facilities with a “critical impact of the operations of the interconnection” and is able to be applied consistently, the SRC recommends that Requirement R1 be modified as follows (see words in red): R1. Each Transmission Owner shall perform an initial risk

assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading that could result in critical, adverse impacts to the operation of the interconnected power system.

Document Name:

Likes: 1 California ISO, 2, Vine Richard

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment:

I support the comments provided by the ISO/RTO Council Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer: No

Answer Comment:

The proposed method of addressing the FERC directive to remove the term 'widespread' meets the specific language in the Order, however, it leaves the responsible entity and the Regional Compliance Organizations with regulatory uncertainty as to the scope of what constitutes 'instability' in regards to Requirement R1. The revised Rationale does little to clarify the issue for the responsible entity and the Regional Compliance Organizations. The Rationale box provides some insight, but does not provide the clarity needed in the standard. FERC stated that only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1. The SDT should build off of this concept to provide the needed clarity in the standard. One option would be too revise the requirement and then qualify what constitutes 'critical impact' from an operational perspective (for example: the loss would result in exceeding an operating limit). The proposed language for R1 is below.

"…The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability that has a critical impact on the operation of the Interconnection, uncontrolled separation, or Cascading within an Interconnection."

The guidance provided in the text box only provides examples of criteria that "may" be considered. Again this provides no regulatory certainty for the responsible entity and the Regional Compliance Organization. Additionally, the guidance reintroduces the concept of an 'area or magnitude of potential impact' which was eliminated

from the Requirement with the deletion of the term ‘widespread’. This concept should be removed from the guidance. Further, this guidance may introduce unintended consequences and could influence a weakening of the criteria established by the Planning Coordinators in response to R6 of TPL-004-1.

Document Name:

Likes: 0

Dislikes: 0

Teresa Cantwell - Lower Colorado River Authority - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Additional Comments

Andrea Basinski – Puget Sound Energy

There are a couple of things which seem confusing:

- There seems to be conflict with timelines, comparing the Standard itself to the Implementation Plan.
  R2.2 places a timeline for completion of 90 calendar days after the completion of the R1 assessment, and word has filtered down that WECC said that if the R1 assessment is completed prior to the effective date, the clock starts ticking on the R2.2 90 days.

  However, the implementation plan says that R2.2 has to be completed with 90 calendar days of the effective date of the Standard. That could be a very different end date for R2.2.

- CIP-014-2 is positioned to become effective the day after CIP-014-1 becomes effective, with -1 being retired at midnight of the same day it becomes effective. This might not be an issue of -1 is superseded by -2, and never becomes effective, but you never know.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2014-04 Physical Security

Comment Period Start Date: 2/20/2015

Comment Period End Date: 4/10/2015

Associated Ballot: 2014-04 Physical Security CIP-014-2 IN 1 ST

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Standards, Valerie Agnew (via email) or at (404) 446-2566.

Summary Consideration:
Most commenters agreed with the proposed revisions to address the directive from FERC Order 802 to remove the term widespread from the standard. The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread". The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry.

Summary of non-substantive revisions:

- Rationale for R1: Edited the second sentence for clarity.
- Rationale for R1 (second paragraph): Added back language that was inadvertently deleted previously.
- Severe VSL for R6: Corrected a reference to Part 6.3 to Part 6.4
- Updated the date in the footer.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
Randi Heise	Dominion - Dominion Resources, Inc.	5		Dominion - RCS	Larry Nash	Dominion Virginia Power	SERC	1
					Louis Slade	Dominion Resources, Inc.	SERC	6
					Connie Lowe	Dominion Resources, Inc.	RFC	3
					Randi Heise	Dominion Resources, Inc,	NPCC	5
	Duke Energy	1,3,5,6	FRCC,SERC,RFC		Doug Hils	Duke Energy	RFC	1

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
Michael Lowman				Duke Ballot Body Members	Lee Schuster	Duke Energy	FRCC	3
					Dale Goodwine	Duke Energy	SERC	5
					Greg Cecil	Duke Energy	RFC	6
Ben Li	Independent Electricity System Operator	2	NPCC	ISO/RTO Council Standards Review Committee	Charles Yeung	SPP	SPP	2
					Christina Bigelow	ERCOT	TRE	2
					Terry Bilke	MICO	MRO	2
					Mark Holman	PJM	RFC	2
					Greg Campoli	NYISO	NPCC	2
					Ali Miremadi	CAISO	WECC	2
					Ben Li	IESO	NPCC	2
Emily Rousseau	MRO	1,2,3,4,5,6	MRO	MRO-NERC Standards	Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
				Review Forum (NSRF)	Amy Casucelli	Xcel Energy	MRO	1,3,5,6
					Chuck Lawrence	American Transmission Company	MRO	1
					Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
					Dan Inman	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
					Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
					Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
					Jodi Jenson	Western Area Power Administration	MRO	1,6
					Larry Heckert	Alliant Energy	MRO	4

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
					Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
					Marie Knox	Midwest ISO Inc.	MRO	2
					Mike Brytowski	Great River Energy	MRO	1,3,5,6
					Randi Nyholm	Minnesota Power	MRO	1,5
					Scott Nickels	Rochester Public Utilities	MRO	4
					Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
					Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
					Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Paul Haase	Seattle City Light	1,3,4,5,6	WECC	Seattle City Light	Pawel Krupa	Seattle City Light	WECC	1

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
					Dana Wheelock	Seattle City Light	WECC	3
					Hao Li	Seattle City Light	WECC	4
					Mike Haynes	Seattle City Light	WECC	5
					Dennis Sismaet	Seattle City Light	WECC	6
Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	SPP	2
					John Allen	City Utilities of Springfield	SPP	1,4
					Hollie Baker	Oklahoma Gas and Electric Company	SPP	1,3,5,6
					Mike Buyce	City Utilities of Springfield	SPP	1,4
					J.Scott Williams	City Utilities of Springfield	SPP	1,4

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
					Louis Guidry	Cleco Power LLC	SPP	1,3,5,6
					Jonathan Hayes	Southwest Power Pool Inc.	SPP	2
					Robert Hirchak	Cleco Corporation	SPP	1,3,5,6
					James Simms	Cleco Power LLC	SPP	1,3,5,6
					Jason Smith	Southwest Power Pool Inc	SPP	2
					Don Schmit	Nebraska Public Power District	MRO	1,3,5

1. The PSSDT has revised CIP-014-1, Physical Security, to address the directive from FERC to to remove the term "widespread" from Reliability Standard CIP-014-1.

Do you agree with the proposed revisions to the standard contained in CIP-014-2 as summarized above? If not, please provide specific comments regarding the revisions and any suggestions for appropriate revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 - TRE

Selected Answer: Yes

Answer Comment:

Response:

Likes:	0
Dislikes:	0

Frank McElvain - Siemens - Siemens PTI - 7 -

Selected Answer:	No
Answer Comment:	The removal of widespread is ok, but there is a larger problem. The CIP-014-2 Standard is missing some fundamental elements in R1 and R2 to assure reliability if the contemplated contingency were to actually occur, and to be consistent with other standards. To approve the standard as currently written creates inconsistencies among the entire family of reliability standards. Station or substation damage would likely include equipment that could currently take as long as 16 months to replace. With such a lengthy period of time in which a damaged station could be out-of-service, the standard needs to explicitly require determination of limits under the system's new normal

condition, and to accommodate more probable N-1 contingencies.

CIP-014 should also be consistent with other NERC standards, such as TOP-004, which requires operation within known operating limits, and preparing for the next contingency within 30 minutes. It is unrealistic to expect these limits to be determined in real-time after a substation-out event as contemplated in CIP-014.

The level of study performed in preparation for a loss of a substation (or station) can vary from one organization to another and not every system limit needs to be determined in advance. However, minimally, CIP-014 should require that generating units are confirmed to remain stable for the next N-1 contingency, that current IROLs are not degraded in the new normal condition, and that generation contingency reserves remain adequate.

Response: The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread". The standard is written to allow flexibility in how the risk assessments are

performed rather than create a prescriptive "one size fits all" requirement.

Likes: 0

Dislikes: 0

Amanda Owen - AEP - NA - Not Applicable - TRE,SPP,RFC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:	Yes
Answer Comment:	
Response:	
Likes:	0
Dislikes:	0

Herb Schrayshuen - Herb Schrayshuen - 2 -

Selected Answer:	No
Answer Comment:	
Response:	
Likes:	0

Dislikes:	0

David Kiguel - David Kiguel - 8 -

Selected Answer:	No
Answer Comment:	My comment addresses the proposed Implementation Plan. While accepting that the change in the proposed standard is minor with respect to the currently approved version, it would be advisable to have an effective date that gives a more reasonable time, e.g. 30 days after the applicable date instead of the proposed day immediately after approval or day after the effective date of Version 1. This in order to permit relevant entities to do any necessary administrative work required for implementation.

Response: The SDT does not believe that the Implementation Plan creates a burden for applicable entities. The SDT does not believe that an entity will need to repeat the initial risk assessment for CIP-014-2.

Likes:	0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: Yes

Answer Comment:

Exelon agrees with the SDT proposal to remove the term “widespread” from Reliability Standard CIP-014-1. With that change we believe the standard is responsive to the directive and supportive of reliability.

We do not agree that an alternative modification is necessary to meet the concern raised in the Directive. Alternative modifications are likely to delay implementation and lead to new revisions requiring further clarification with no appreciable gain in reliability.

Response: Thank you for your support.

Likes: 0

Dislikes: 0

Allen Wallace - Fayetteville Public Works Commission - 3 -

Selected Answer: No

Answer Comment:

The concern with removing the term "widespread" is that it potentially imposes the requirements of the standard upon smaller substations and entities that could have minimal impact on the BES. While I would prefer a more quantifiable determinant of applicability (customers affected, miles of transmission, load or generation lost, etc.) I believe that widespread is better than no discriminant at all.

Response: The language of the requirement was revised to meet the FERC directive to remove the term 'widespread" and has been widely accepted by industry. The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not

provide clarity and resulted in similar ambiguity to the use of "widespread".

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

With the word "widespread" removed, R1 is stating that if rendering a station inoperable results in any instability (large or small), the station should be declared critical. Depending on the severity of an instability, there may or may not be an impact on the operation of the interconnection. We are proposing the following modification to R1 to make it clearer in terms of reliability impact on the "Interconnection" in which the assessed facilities lie.

"Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months)

that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in a critical impact on the operation of the interconnected (or neighboring) power system by causing instability, uncontrolled separation, or Cascading within an Interconnection."

Response: Use of the term "critical impact" does not provide any more clarity or guidance than using the term "widespread". The SDT decided to provide language in the guidance rather than try to revise the requirement to address the directive to remove "widespread".

Likes:	1	Herb Schrayshuen, 2, Schrayshuen Herb
Dislikes:	0	

Brian Shanahan - National Grid USA - 3 -

Selected Answer:	Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Stephen Pogue - M and A Electric Power Cooperative - 3 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Matt Jastram - Portland General Electric Co. - 5 -

Selected Answer:	Yes
Answer Comment:	
Response:	
Likes:	0
Dislikes:	0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer:	Yes
Answer Comment:	Seattle City Light supports the proposed revisions expressed in draft CIP-014-2 to remove the undefined term "widespread" and votes affirmative. In particular Seattle supports the new guidance language added to the Standard and supporting documents to explain what is meant by the term "widespread" that would no longer be included in the Standard.

		Seattle, however, would support the proposed draft further if the term "widespread" was not simply removed from CIP-014-2 but replaced everywhere by "critical." Although "critical" is no more defined than "widespread," the term is the exact word used by FERC in its Order requesting removal of "widespread" and relates directly to FERC and NERC guidance on the matter.
Response: Use of the term “critical impact” does not provide any more clarity or guidance than using the term “widespread”. The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove “widespread”. The SDT considered additional descriptive language in the requirement to replace “widespread” but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of “widespread”.		
Likes:	0	
Dislikes:	0	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:	Yes
Answer Comment:	
Response:	
Likes:	0
Dislikes:	0

Donna Turner - APS - Arizona Public Service Co. - 1,3,5,6 - WECC

Selected Answer:	No
Answer Comment:	All though we agree the with the removal of the word “widespread” from the standard, we feel leaving the word “instability” in the standard still makes it vague and inconsistent. We suggest that both word “widespread” and “instability” be taken out to read R1 as follows:

"… The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in uncontrolled separation, or Cascading within an Interconnection.

The criticality of a facility to an interconnection is determined by its impact and not by instability. Instability is a symptom and not the final consequence. There are various types of instabilities and with consequence varying from a small 10 W generation tripping to an interconnection braking up and many things in between. There are many other symptoms which are also indicators of cascading such as excessive overload, very low voltages etc. but none of them are called out. So why leave instability in there?

The above proposed wording preserves all of the impact without dwelling on symptoms.

Response: The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry. The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but

decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread".

Likes: 0

Dislikes: 0

Matt Stryker - Matt Stryker On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Selected Answer:	Yes
Answer Comment:	
Response:	
Likes:	0
Dislikes:	0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:	No
Answer Comment:	**FERC Order No. 802 states on page 18:** "The definition in Requirement R1 should not be dependent on how an applicable entity interprets the term "widespread" but instead should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and

therefore subject to Requirement R1."

Rather than merely remove the word "widespread," NERC could better comply with the FERC order to provide clarity with a simple rearrangement of terms.

By reordering R1 from:

…if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

To:

…if rendered inoperable or damaged could result in uncontrolled separation or Cascading within, or the instability of, an Interconnection.

This reorganization maintains all the wording of R1 without introducing any undefined or subjective terms, but more clearly ties the term "instability" to "Interconnection." This better reflects the FERC intention of affecting an interconnection, and by changing the intervening modifier between the terms "instability" and "Interconnection" from "within" to "of" addresses the industry concern that R1, as left without the term "widespread," could be interpreted as applying to localized areas of instability

Response: The SDT made the decision to add guidance and rationale rather than to expand

on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread". The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry.

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

ERCOT supports and references the comments to be filed by the ISO/RTO Council Standards Review Committee.

Response: Thank you for your support.

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Catherine Wesley - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

While we agree that the revision addresses the directive, it's unfortunate that this required change muddles common understanding of NERC's terms and definitions.

Response: Thank you for your comment.

Likes: 0

Dislikes: 0

Bob Reynolds - Southwest Power Pool Regional Entity - 10 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Michael Lowman - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Duke Energy would like to thank the SDT for their efforts on this project. In addition, we agree with the changes made by the SDT.

Response: Thank you for your comment.

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Selected Answer: Yes

Answer Comment:

NSRF's concerns with the proposed changes to CIP-014-2 standard.

1. Removal of the term , "widespread", from R1 without replacement text in R1 - The qualifying concept of "widespread" was removed from R1 without replacing it with alternate text to address the Commission's concerns. This approach makes the text in R1 even less defined than the original CIP-

014-1 text. For example, the modified text offers no criteria to define the degree of reliability impacts due to instability or uncontrolled separation that would qualify a substation. This approach would allow applicable entites and regulators to interpret even minor or the R1 text to expect a substation to be qualified by local or minor reliability impacts as qualifying a substation. Addressing the Commission's concerns by relegating criteria text to the Rationale for R1, rather than including criteria text in R1, allows the text to be disregarded because the rationale will be removed when the standard is finalized. Addressing the Commission's concerns by relegating text to to the Guidance and Technical Basis section, rather than including text in R1, allows the text to be disregarded because, not being part of R1, the the application of guidance text may be a judgement call. Our concern stems from FERC Order 693, section 253, which states that ". . . compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts . . .". Each requirement must be clearly written for entities to follow. Any wording contained in a Guidance and Technical document is just that, wording. The words of "the Requirements within a standard define what an entity must do to be compliant".

Alternate text for R1 to replace2. Limiting the applicability of the term, "widespread"", to just instability – We interpret the qualification that the widespread reliability impact duerefers to "all three qualifying conditions – instability", ",

uncontrolled separation" and "Cascading, not to just instability alone.

3. Insufficient Use of NERC-Defined Terms - Alternate text for "widespread" should incorporatebe added to Requirement R1 and should make as much use of NERC defined-terms and concepts as much as possible. The NERC-defined term of "Adverse Reliability Impact" is used in Criterion 2.3 from Attachment 1 of the CIP-002-5.1 standard andFor example, the NERC-defined concept of "Interconnection Reliability Operating Limit" (IROL) is used in Criterion 2.9 from Attachment 1 of the CIP-002-5.1 standard. The FAC-010-2 standard already allows Planning Coordinators (PCs) to establishdefine criteria and methodology for establishing planning horizon IROLs that are appropriate for the PC's area and the Interconnection where the limit will be applied.

Based on the preceding comments, 4. Clarification of the term, Interconnection – We interpret that the use of capitalized word "Interconnection" within the Purpose, R1, R1.1 bullet 1 and 2, and associated VSLs refers to any of the Eastern, Western, ERCOT or Quebec Interconnections, not a regional Balancing Authority interconnection or regional Independent System Operator interconnection.

NSRF suggests **recommends the following wording changes to address the above**

concerns:

For Requirement R1, we suggest that the term, “widespread” in R1 be replaced with text like, “. . . if rendered inoperable or damaged could result an Adverse Reliability Impact on the BES within an Interconnection due to instability, uncontrolled separation, or Cascading” or “. .. . if rendered inoperable or damaged could result in the violation of one or more Interconnection Reliability Operation Limits (IROLs) within an Interconnection due to instability, uncontrolled separation or Cascading within, or instability of, an Interconnection”.

Also based on the preceding comments, ATC suggests revising the wording of the draft text in **For the R1 Rationale and** in the **Guidance and Technical Basis** section. ATC proposes that the wording near the end **Section**, we suggest the following modifications:

- {C}· Replace the wording of “The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the clarification text be simplified to focus following: Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6; NERC EOP-004-2 reporting criteria; Area or magnitude of potential impact” with text that focuses on the concept on Adverse Reliability Impact or IROLs with language like, “The Transmission Owner should derive the criteria for the R1 risk assessment from the criteria used in the

Adverse Reliability Impact definition or the criteria used to establish planning horizon IROLs as inper Requirement R3 of the NERC FAC-010-2 reliability standardReliability Standard."

- Add clarification regarding the four kinds of instability that should be considered with wording like, "The consideration of instability should include all four kinds of instability - steady state voltage instability, steady state angular instability, dynamic voltage instability, and dynamic angular instability."

Response: 1-3: The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread". The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry. The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry.
4: You are correct.

Likes:

3 Nebraska Public Power District, 5, Schmit Don
Nebraska Public Power District, 3, Eddleman Tony

Nebraska Public Power District, 1, Cawley Jamison

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

Although we agree with removal of the term "widespread" from the standard, we do not find the supporting justification provided in the Rationale for R1 and/or the Guidelines and Technical Basis for R1 to be adequate and/or convincing. Specifically, we do not find the three proposed criteria for critical impact as particularly instructive to help identify which instability – out of the potentially several instabilities seen in the transmission analyses performed for R1 – would qualify as having a critical impact on the operation of the interconnection. Without a clear technical guidance on what are the attributes (quantitative and qualitative) of a "critical impact" instability" – that is, only an instability that has a critical impact on the operation of the interconnection, as stated in the March 7, 2014 Order – we do not see how the "excessive uncertainty in identifying critical facilities under R1" due to the undefined term

"widespread" has been effectively addressed. Deletion of "widespread" without replacing it with adequately clear technical guidance on what constitutes a "critical impact instability" for an interconnection has only displaced the excessive uncertainty concern of FERC from "stability" to "critical impact" – it has not resolved it.

Since at least two of the three proposed criteria for critical impact puts the onus on the Transmission Owner (or its Transmission Planner) to determine (quantify) the "area or magnitude of potential impact" or determine how to identify "System instability" per R6 in TPL-001-4, this approach is prone to result in "critical impact" criteria that differ widely among the numerous Transmission Owners within each of the three Interconnections. This outcome would be incompatible and inconsistent with FERC's stated guidance in the March 7, 2014 Order – and reiterated in the November 20, 2014 Order – that "***only*** an instability" that has a "critical impact on the operation ***of the interconnection***" (emphasis added) warrants finding that the facility resulting in the [critical interconnection impact] instability is deemed critical under Requirement R1.

We suggest the following two alternatives to address the above concerns:

1) Option 1: Enhance the technical guidance to provide a common Interconnection-wide criterion for what constitutes "critical impact" instability in the Interconnection. This would conceivably be

different for each of the three Interconnections, resulting in three “critical impact” instability criteria. We note that this approach would be similar to what was adopted for the Order 754 stability studies/analyses. As such, we recommend using “Table C – Performance Measures” in the NERC Order 754 Data Request document as a good paradigm for developing an Interconnection-wide “critical impact” instability criteria.

2) Option 2: Modify Requirement R1 to recognize that only an instability that results in Cascading or uncontrolled separation within an Interconnection qualifies as one that has a “critical impact on the operation of the Interconnection”. This approach implicitly acknowledges that all other instabilities have a limited (local) impact and therefore do not result in widespread instability, and widespread instability is synonymous with Cascading or uncontrolled separation. The following change in R1 and part 1.1 is suggested: “….could result in Cascading or uncontrolled separation within an Interconnection caused by (voltage or angular) instability and/or successive failures of overloaded Facilties.”

Aside from the above, we suggest that the following compound sentence in the Rationale as well as Technical Basis be simplified and restructured to remove the existing contextual ambiguities that make comprehending its intent very difficult.

“The requirement is not to require

identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged."

Further, we question if this sentence even belongs in the Rationale – it is hard to see how this provides a justification for Requirement R1. In fact, saying that "The requirement is not to require identification of…" appears to contradict the intent of the following verbiage in R1 "… transmission analyses designed to identify the…".

Lastly, it appears that the changes made in the following paragraph in the Rationale for R1 have inadvertently resulted in an incomplete/incoherent sentence within the parenthesis.

[It] **Requirement R1** also meets the [portion of the] **FERC** directive [from paragraph 11] for periodic reevaluation **of the risk assessment** by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment [any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled

separation, or Cascading within an Interconnection]).

Response: The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread". The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry. The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry.

Regarding your proposed edits to the Rationale for R1, the SDT concurs and has revised the language for clarity and to add the language previously deleted.

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:	Yes
Answer Comment:	
Response:	
Likes:	0
Dislikes:	0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Selected Answer:	No
Answer Comment:	With the word “widespread” removed, Requirement R1 implies that if and when a station becomes inoperable and a potential threat for instability (large or small), uncontrolled separation or cascading, the station should be declared critical. Depending on the severity of an instability, there may or may not be any adverse impact on the operation of the

		interconnection. For example, if a station in a pocket or remote area should become inoperable and a potential threat for instability, it may not create any adverse impact on interconnected operations. Hence, to capture the intent of the requirement such that it addresses facilities that can impact interconnected operations, suggest modifying R1 as follows (see words underlined and in bold): R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in **a critical impact on the operation of the interconnected power system by causing** instability, uncontrolled separation, or Cascading within an Interconnection. For the Rationale Box for R1, we suggest replacing “among other criteria” with “for example.” This wording clarifies that the examples given are merely examples and not the only options for determining critical impact.

"[…] the Transmission Owner may determine the criteria for critical impact by considering, **for example**, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact"

In paragraph 6 of the FERC Docket No. RD14-6-000, "interconnection" is lower case. Should "interconnection" as used in the standard's Rationale for Requirement R1 and in the Guidelines and Technical Basis on page 31 be upper or lower case?

To make the wording of the Rationale for Requirement R1 consistent with the wording in RD14-6-000, suggest rewording the second sentence to read"…applicable Transmission Owner determines through objective analysis, technical expertise, and experienced judgment…"

R6 Severe VSL: "The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part

6.3” should read “per Part 6.4”.

Response: Use of the term “critical impact” does not provide any more clarity or guidance than using the term “widespread”. The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove “widespread”. The SDT considered additional descriptive language in the requirement to replace “widespread” but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of “widespread”. The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry.

The use of Interconnection is intended to be one of the four Interconnections and the word should be capitalized.

The SDT considered revising the rationale based on your comment but decided to retain the original language. The SDT revised the R6 Severe VSL per your comment.

Likes:

2 Con Ed - Consolidated Edison Co. of New York, 1,3,5,6, Dash Kelly
Con Ed - Consolidated Edison Co. of New York, 1, de Graffenried Chris

Dislikes: 0

Michael Mertz - PNM Resources - 3 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer: No

Answer Comment:

Removing "widespread" from criteria will leave the Reliability Standard open to "local" impact assessments by the audit teams, which could have exponential implications even for small municipal utilities. Removing the term "widespread" opens the scope of the standard to unlimited interpretation. The term "widespread" has been commonly and generally used since the mandatory and effective date of the NERC Reliability Standards to exclude such common occurrences as a storm moving through the area (daily during the summer in Florida), causing damage up to and including some

transmission outages. Would a lightning strike on a bulk power substation causing it to operate be termed instability under the Reliability Standard or would the lightning strike also have to cause the connecting transmission lines to operate? Therefore, does removal of the word "widespread" for consideration of instability mean that every bulk power facility outage, for whatever reason is now in violation of instability? There has to be some degree of limiting language to prevent the unintended spiral that removal of the word "widespread" will cause. Entities are familiar with and understand the use of the term "widespread". Removing this modifier from the scope of assessment will require extensive instruction and scenario analysis to make the scope of the assessment clear.

Response: The additional guidance contained in the standard was developed to avoid inclusion of local impacts that would be adverse to reliability.

Likes:	2	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott Tallahassee Electric (City of Tallahassee, FL), 5, Webb Karen
Dislikes:	0	

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Kent Kujala - DTE Energy - Detroit Edison Company - 3 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Daniel Herring - DTE Energy - Detroit Edison Company - 4 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Warren Cross - ACES Power Marketing - 6 - MRO,TRE,SERC,SPP,RFC

Selected Answer:	No
Answer Comment:	1. The removal of the undefined term of "widespread" from R1 should have alternate text to address the Commission's concern(s) and to provide industry with clarity to the applicability of transmission facilities. While we understand the drafting team's response to FERC's directive to remove "widespread," this language should be modified to make clear that a facility that has a critical impact on the operation of an Interconnection is critical and therefore subject to Requirement R1. This blanket removal of 'widespread' from the requirements makes the text in R1 even more vague and subjective than the original CIP-014-1 language that is subject to interpretation and may result in a standard that is not auditable. By removing the word widespread, there is no clear delineation of reliability impact(s) due to instability or uncontrolled separation that would qualify a substation. This language change will cause inconsistent implementation across the regions and Transmission Planners or Planning Coordinators. Furthermore, given the cost implications on a possible Transmission Owner, more clarity and certainty of scope is needed. 2. Adding to the Rationale and Guideline and Technical Basis for Requirement R1 does not address the FERC Directive. The

		Rationale section while assisting industry to better understand the intention of the PSSDT is not enforceable and will result in an inconsistent R1 implementation across the regions. 3. The PSSDT should refer to NERC defined-terms and concepts, where appropriate. To add clarity to 'widespread,' the PSSDT should consider the NERC defined terms of "Adverse Reliability Impact" (Criterion 2.3 from Attachment 1 of the CIP-002-5.1), "Interconnection Reliability Operating Limit" (Criterion 2.9 from Attachment 1 of the CIP-002-5.1), and the FAC-010-2 standard that is in place to assist Planning Coordinators (PC) to establish planning horizon IROLs that are appropriate for the PC's area and the Interconnections. 4. Thank you for time, attention and consideration regarding these CIP-014-2 comments.
Response: Rationales and guidance also inform auditors of the intentions of the drafting team to help ensure consistent auditing of the requirements.		
Likes:		0

Dislikes:	0

Dan Bamber - ATCO Electric - 1 - WECC

Selected Answer:	Yes
Answer Comment:	Agree that removing the term widespread removes some subjectivity, however additional clarity on what is meant by the term “instability” would be beneficial in helping entities determine the appropriate critiera to be applied, as part of their risk assessment, in the identification of facilities in-scope to this standard.
Response: Instability refers to voltage or frequency instability and is widely accepted by industry.	
Likes:	0
Dislikes:	0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:	Yes
Answer Comment:	With the deletion of the term "widespread" from CIP-014, the TO must *determine* whether instability, uncontrolled separation, or Cascading within an Interconnection could occur if the station was damaged or rendered inoperable. For jointly-owned facilities, i.e., two or more TOs at a Transmission station or Transmission substation, the Standard states the following on page 30 of 39: "On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards." In order to delegate responsibility to a single TO at a jointly-owned facility to make the above cited determination and the remaining Requirements in the Standard, Seminole Electric has the following questions:

		(1) Can a Coordinated Functional Registration agreement (CFR), Joint Registration Organization agreement (JRO), or Memo of Understanding (MOU) be drafted on a station-by-station basis between parties? Seminole Electric is unaware whether CFRs and JROs can be developed and approved by NERC on a station-by-station basis and requests more information on this issue. (2) In delegating responsibility for the Requirements in jointly-owned facilities under CIP-014-2, can an MOU be a sufficient mechanism to delegate authority if drafted sufficiently, or does the drafting team reason that ultimately a CFR or JRO must be executed between the co-owners (multiple TOs) at a station? Seminole Electric has been told that MOUs may be ineffective in delegating responsibility for the Requirements for jointly-owned facilities and that CFRs and JROs should be executed instead.
Response: As long as a particular station or substation has been assessed, the drafting team does not have a preference as to how this is achieved. The joint-owners have to address the performance of this standard just like any other NERC standard that is applicable.		
Likes:	0	

Dislikes:	0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:	Yes
Answer Comment:	Hydro One Networks Inc. supports the comments advanced by the NPCC RSC.
Response:	
Likes:	0
Dislikes:	0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:	No

Answer Comment:

Hydro-Quebec TransEnergie supports the comments from NPCC-RSC

Response:

Likes: 0

Dislikes: 0

Steve Johnson - Western Area Power Administration - 1 -

Selected Answer: No

Answer Comment:

Western Area Power Administration supports the Bureau of Reclamation comments regarding the removal of "widespread". Specifically, we request the adoption of language referring to TPL-001-4 R6 for consistency.

Response: The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC

directive to remove “widespread”. The SDT considered additional descriptive language in the requirement to replace “widespread” but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of “widespread”. The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry. The SDT has added a reference to TPL-001-4, R6 in the rationale for R1 as well as in the guidance for R1.

Likes: 0

Dislikes: 0

Michael DeLoach - AEP - 3 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes:	0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer:	No
Answer Comment:	The group has a concern in reference to the removal of the term 'widespread' in that removing it doesn't provide any boundries to the scope of the instability or cascading outages. With that being said, this can lead to continued inconsistency throughout the industry. We understand that the Commission has a large concern about the term 'widespread' being in the doucmenation and the group would like to propose alternative language stated as followed: "instability uncontrolled separation or cascasding that would cause or affect an Operational IROL within the Interrconnection". The group also has a concern pertaining to CIP-014 in reference to a Transmission Owner completing their assessment (which is due on or before October 15, 2015) more than 90 days before October 1. There is some confusion on when the verification would be completed (if the assessment was finished June 1). Does the Transmission

		Owner have 90 days from October 1 or 90 days from June 1? This would be with the assumption that the effective date is October 1. We would like the drafting team to provide more clarity in reference to Requirement R2.2 addressing this issue. We have a concern about Requirement R4 and its timeline requirement. In the standard's Rationale Box for R4 (second paragraph), it states "Requirement R4 doesn't explicitly states when the evaluation has to be completed" however, Requirement R5 development of a security plan(s) depend on this information. We would like for the SDT to provide more detailed information on when the evaluation needs to be completed. First line of the first paragraph of Requirement R3…. Page 9. The term 'control center' should be capitalized as its shown the Glossary of Terms. Additionally, this applicable for the last sentence of the paragraph. First line of the first paragraph of Requirement R5…. Page 11. The term 'control center' should be capitalized as its shown the Glossary of Terms.
	Response: The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but	

decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread". The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry. The SDT made the decision to add guidance and rationale rather than to expand on the requirement.

R1 must be completed on or before October 1. Entities have 90 days from October 1 to complete R2.

R4 and R5 are linked and must be completed 120 days after completion of R2. The SDT didn't develop a specific timeline to allow for flexibility in how an entity performed the two requirements. Rather than say, for example, that R4 must be completed in 60 days and R5 must be completed in an additional 60 days, the SDT allowed flexibility in when these two requirements are performed.

The SDT has used the undefined term "control center" throughout the standard. This was used because the definition of "Control Center" contains the Reliability Coordinator and Balancing Authority, which are not applicable under CIP-014-2.

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:	No
Answer Comment:	The Bureau of Reclamation (Reclamation) does not agree with removing the term "widespread" from R1 without adding clarifying language in the text of the standard. This approach makes the text in R1 even less defined than the original CIP-014-1 text because it offers no criteria of what degree of reliability impacts due to instability or uncontrolled separation is appropriate to determine facilities identified under R1. This approach could cause a much broader range of facilities to come within the scope of the standard by allow interpretations that even minor or local reliability impacts result in some degree of "instability… within an interconnection." Reclamation is concerned that the removal of the term "widespread" could expand the standard to include remote facilities that if lost could impact relatively small and isolated load pockets. Reclamation suggests that the drafting team include a footnote referencing TPL-001-4 R6 criteria, reference other specific criteria like facilities affecting IROLs, or at least incorporate FERC's language "has a critical impact on the operation of the interconnection" into the

		language of R1. In the alternative, the drafting team could reference a specific area or magnitude of potential impact. Unlike the rationale statement, clarifying requirement language or a footnote would be an enforceable component the standard if approved by FERC. The clarifying language would ensure that the scope of facilities identified under R1 would not be dramatically broadened with the removal of the term "widespread."
Response: The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread". The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry. The SDT included a reference to TPL-001-4, R6 in the rational and guidance for R1.		
Likes:	0	
Dislikes:	0	

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer: No

Answer Comment:

I am voting NO because I believe the Standard should be very specific as to what constitutes "damaged", if it is not equal to being "inoperable", as used in the Standard. Also, the Standard needs to be very specific about the method of "transmission analysis" for rendering the station "inoperable", such as complete loss of the station resulting in a three phase fault on the station bus, etc.. The Standard is very specific and clear as how to determine which facilities need to be analyzed (i.e., those exceeding an aggregate weighted value of 3000 as specified in Section 4.1.1.2), and it needs to be just as specific in defining "damaged" and the method of "transmission analysis".

Thank you.

Sincerely,

Spencer Tacke, MID

Response: The SDT made the decision to add guidance and rationale rather than to expand

on the requirement to address the FERC directive to remove "widespread". This guidance includes a reference to TPL-001-4, R6. The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread". The language of the requirement mirrors the language of the FERC order and has been widely accepted by industry.

Likes: 0

Dislikes: 0

Fuchsia Davis - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Selected Answer: No

Answer Comment:

With the removal of the term “widespread,” Requirement R1 implies that, if and when a station becomes inoperable and a potential threat for instability (large or small), uncontrolled separation or Cascading, the station should be declared critical. However, whether there is an adverse impact on the “operation of the interconnection” depends on the severity of an instability. In particular, a station or substation may create local instability, but there may or may not have an adverse or critical impact on the “operation of the Interconnection.” For example, if a station in a pocket or remote area should become inoperable and a potential threat for instability, it may create local instability, but such local instability may not impact the operation of the interconnected system in any way. Hence, to declare such a station as “critical” would defeat the purpose of focusing security operations on those stations and substations that have a “critical impact on the operation of the Interconnection.”

The SRC appreciates that the Standard Drafting Team attempted to provide additional criteria to determine the criticality of impact by providing some guidance in the rationale section for Requirement R1. However, the SRC respectfully suggests that there is a potential that such guidance may result in diverse criteria regarding criticality, which would, in turn, result in substantially different determinations of criticality across and within the Interconnections. It may also create unintended complications regarding compliance with and activities performed under other reliability standards. Hence, given the interconnected nature of the grid and the reliability standards with which Transmission Operators and Owners must comply and to ensure that the requirement effectively conveys the intent to address facilities with a "critical impact of the operations of the interconnection" and is able to be applied consistently, the SRC recommends that Requirement R1 be modified as follows (see words in red):

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could cause

instability, uncontrolled separation, or Cascading that could result in critical, adverse impacts to the operation of the interconnected power system.

Response:
The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread".

Likes: 1 California ISO, 2, Vine Richard

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment:

I support the comments provided by the

ISO/RTO Council Standards Review Committee

Response: Thank you for your comment.

Likes: 0

Dislikes: 0

Peter Heidrich - Florida Reliability Coordinating Council - 10 -

Selected Answer: No

Answer Comment:

The proposed method of addressing the FERC directive to remove the term 'widespread' meets the specific language in the Order, however, it leaves the responsible entity and the Regional Compliance Organizations with regulatory uncertainty as to the scope of what constitutes 'instability' in regards to Requirement R1. The revised Rationale does little to clarify the issue for the responsible entity and the Regional Compliance Organizations. The Rationale box provides some insight, but does not provide the clarity needed in the standard.

			FERC stated that only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1. The SDT should build off of this concept to provide the needed clarity in the standard. One option would be too revise the requirement and then qualify what constitutes 'critical impact' from an operational perspective (for example: the loss would result in exceeding an operating limit). The proposed language for R1 is below. "…The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability that has a critical impact on the operation of the Interconnection, uncontrolled separation, or Cascading within an Interconnection." The guidance provided in the text box only provides examples of criteria that "may" be considered. Again this provides no regulatory certainty for the responsible entity and the Regional Compliance Organization. Additionally, the guidance reintroduces the concept of an 'area or magnitude of potential impact' which was eliminated from the Requirement with the deletion of the term 'widespread'. This concept should be removed from the guidance. Further, this guidance may introduce unintended

consequences and could influence a weakening of the criteria established by the Planning Coordinators in response to R6 of TPL-004-1.

Response: The SDT made the decision to add guidance and rationale rather than to expand on the requirement to address the FERC directive to remove "widespread". The SDT considered additional descriptive language in the requirement to replace "widespread" but decided against doing so because the additional descriptors did not provide clarity and resulted in similar ambiguity to the use of "widespread".

Likes: 0

Dislikes: 0

Teresa Cantwell - Lower Colorado River Authority - 1 -

Selected Answer: Yes

Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Additional Comments

Andrea Basinski – Puget Sound Energy

There are a couple of things which seem confusing:

- There seems to be conflict with timelines, comparing the Standard itself to the Implementation Plan.
  R2.2 places a timeline for completion of 90 calendar days after the completion of the R1 assessment, and word has filtered down that WECC said that if the R1 assessment is completed prior to the effective date, the clock starts ticking on the R2.2 90 days.

  However, the implementation plan says that R2.2 has to be completed with 90 calendar days of the effective date of the Standard. That could be a very different end date for R2.2.

  Response: The Implementation Plan is correct. The third party verification is to be completed within 90 days of the effective date of the standard, October 1, 2015.

- CIP-014-2 is positioned to become effective the day after CIP-014-1 becomes effective, with -1 being retired at midnight of the same day it becomes effective. This might not be an issue of -1 is superseded by -2, and never becomes effective, but you never know.

  Response: The Implementation Plan calls for the retirement of -1 immediately prior to the effective date of -2 so that there is no overlap of compliance.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. A revised SAR was approved by the Standards Committee on December 9, 2014 to address the directives issued in FERC Order No. 802 issued on November 20, 2014, in Docket No. RD14-15-000, *Physical Security Reliability Standard*, 146 FERC ¶ 61,140 (2014). The appointed Physical Security Standard Drafting Team made the revisions to the standard.

Description of Current Draft

This is the first draft of the proposed Reliability Standard, and it is being posted for a 45-day comment and concurrent initial ballot period. This draft includes proposed revisions to address the directives issued in FERC Order No. 802.

Anticipated Actions	Anticipated Date
45-day Comment and Initial Ballot.	February-March, 2015
10-day Final Ballot.	April, 2015
BOT Adoption.	May, 2015
File with applicable Regulatory Authorities.	June, 2015

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-2

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-2.

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

Rationale for Requirement R3:

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

Rationale for Requirement R4:

This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified

and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

Rationale for Requirement R5:

This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

Rationale for Requirement R6:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk	Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1	completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 Applicability

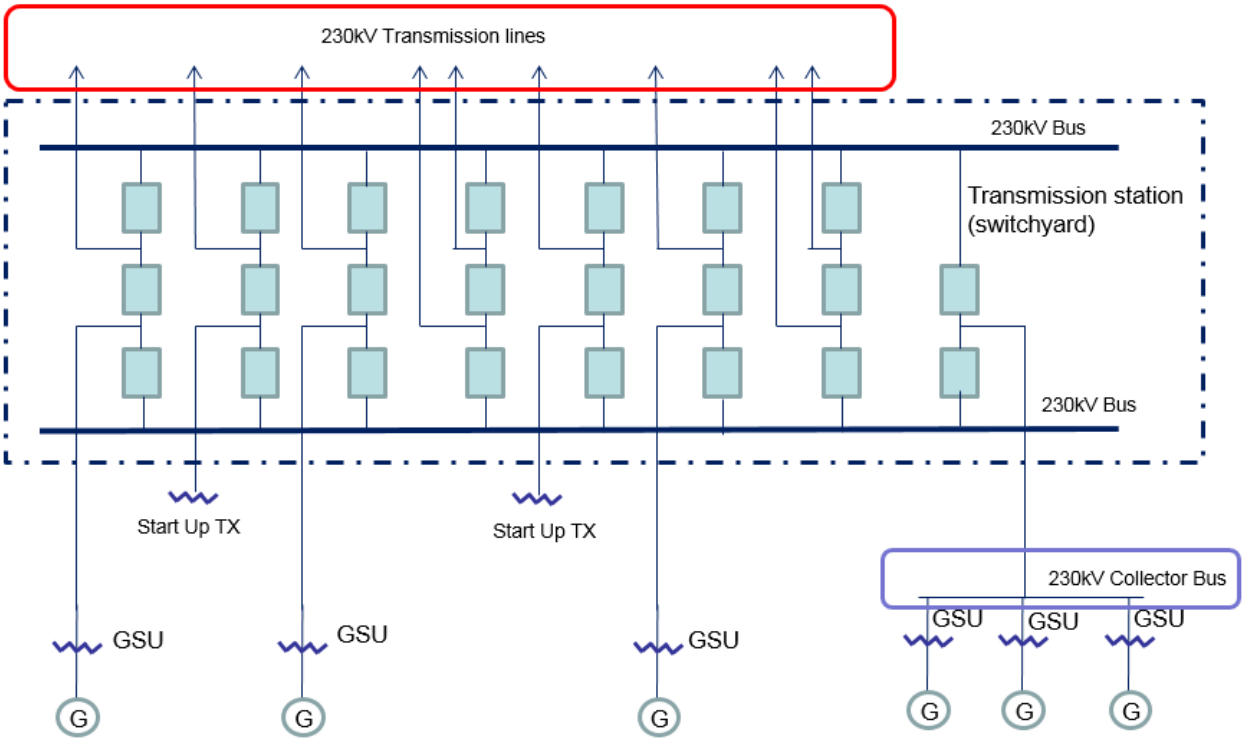
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center

"operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2

is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

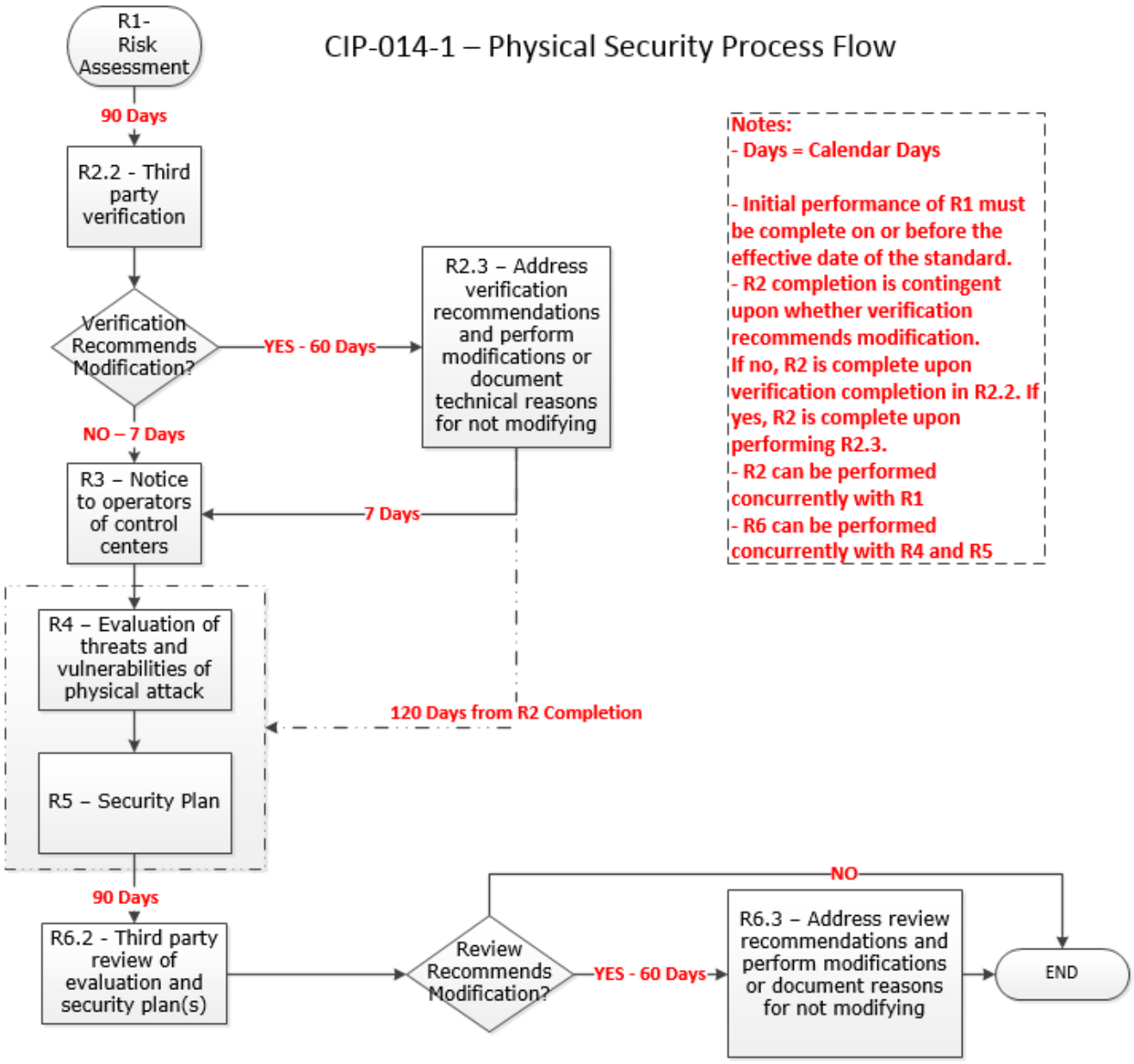
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. A revised SAR was approved by the Standards Committee on December 9, 2014 to address the directives issued in FERC Order No. 802 issued on November 20, 2014, in Docket No. RD14-15-000, *Physical Security Reliability Standard*, 146 FERC ¶ 61,140 (2014). The appointed Physical Security Standard Drafting Team made the revisions to the standard.

Description of Current Draft

This is the first draft of the proposed Reliability Standard, and it is being posted for a 45-day comment and concurrent initial ballot period. This draft includes proposed revisions to address the directives issued in FERC Order No. 802.

Anticipated Actions	Anticipated Date
45-day Comment and Initial Ballot.	February-March, 2015
10-day Final Ballot.	April, 2015
BOT Adoption.	May, 2015
File with applicable Regulatory Authorities.	June, 2015

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-2~~1~~

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-2.

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is ~~not to require identification of, and thus,~~ not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).[A1]

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

Rationale for Requirement R3:

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

Rationale for Requirement R4:

This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified

and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

Rationale for Requirement R5:

This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

Rationale for Requirement R6:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk	Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1	completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4~~3~~.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 Applicability

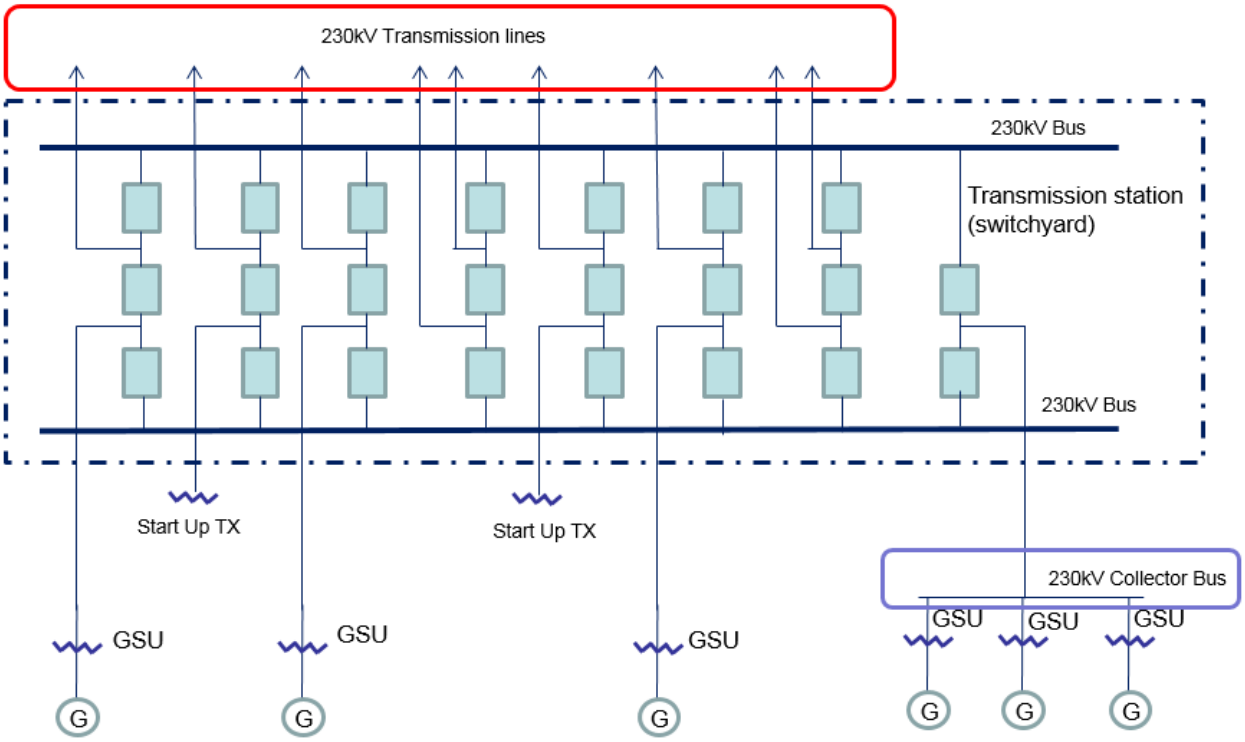
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not ~~to require identification of, and thus, not~~ intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center

"operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2

is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

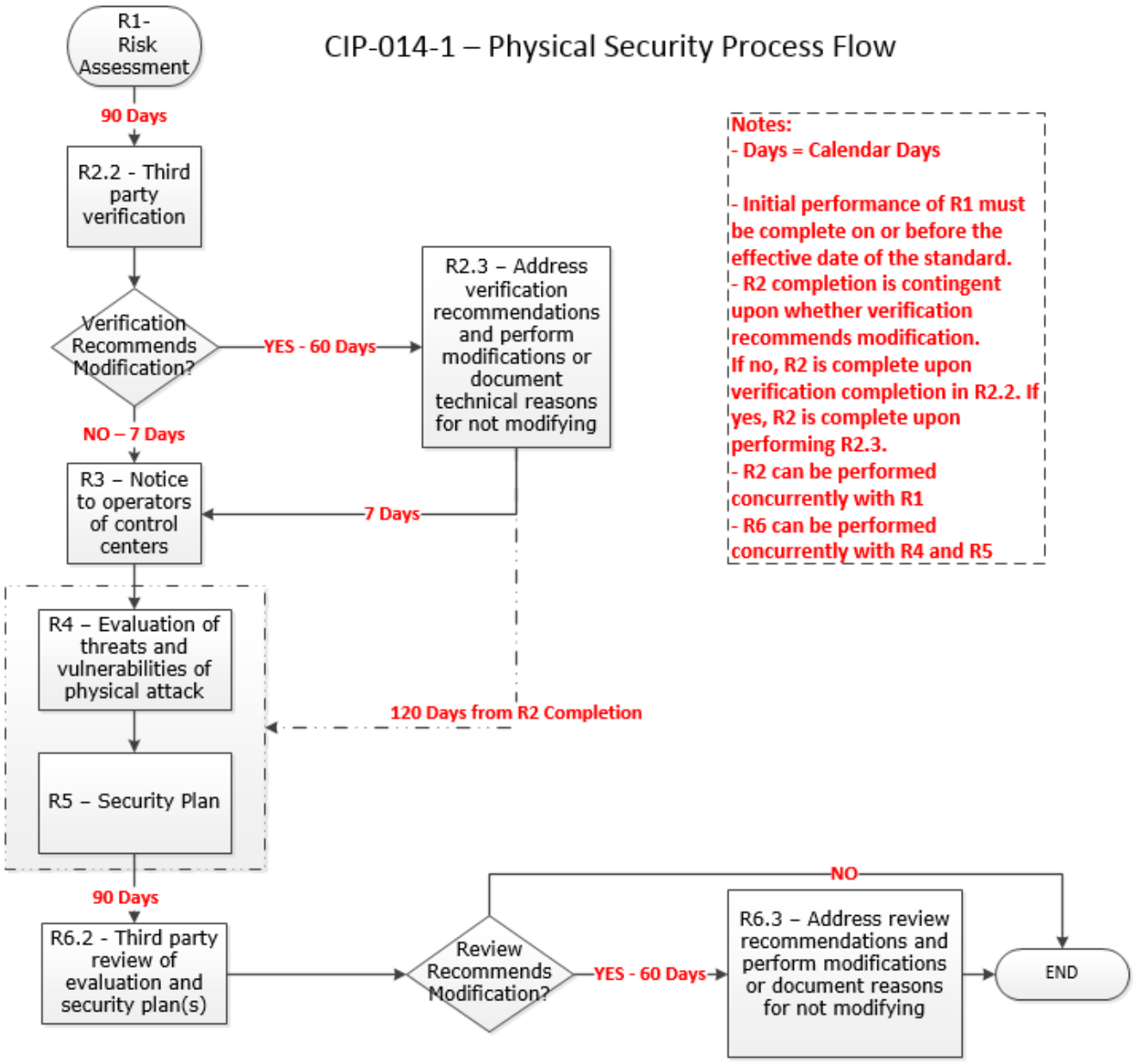
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
NO
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-21

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan.~~CIP-014-1 is effective the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In those jurisdictions where regulatory approval is not required, CIP-014-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner

shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified

Protection Professional (CPP) or Physical Security Professional (PSP) certification.

- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an	result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an	instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection	Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.43.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 13, 2014	Adopted by NERC Board of Trustees	
1	November 20, 2014	FERC Order approving CIP-014-1	

Guidelines and Technical Basis

Section 4 Applicability

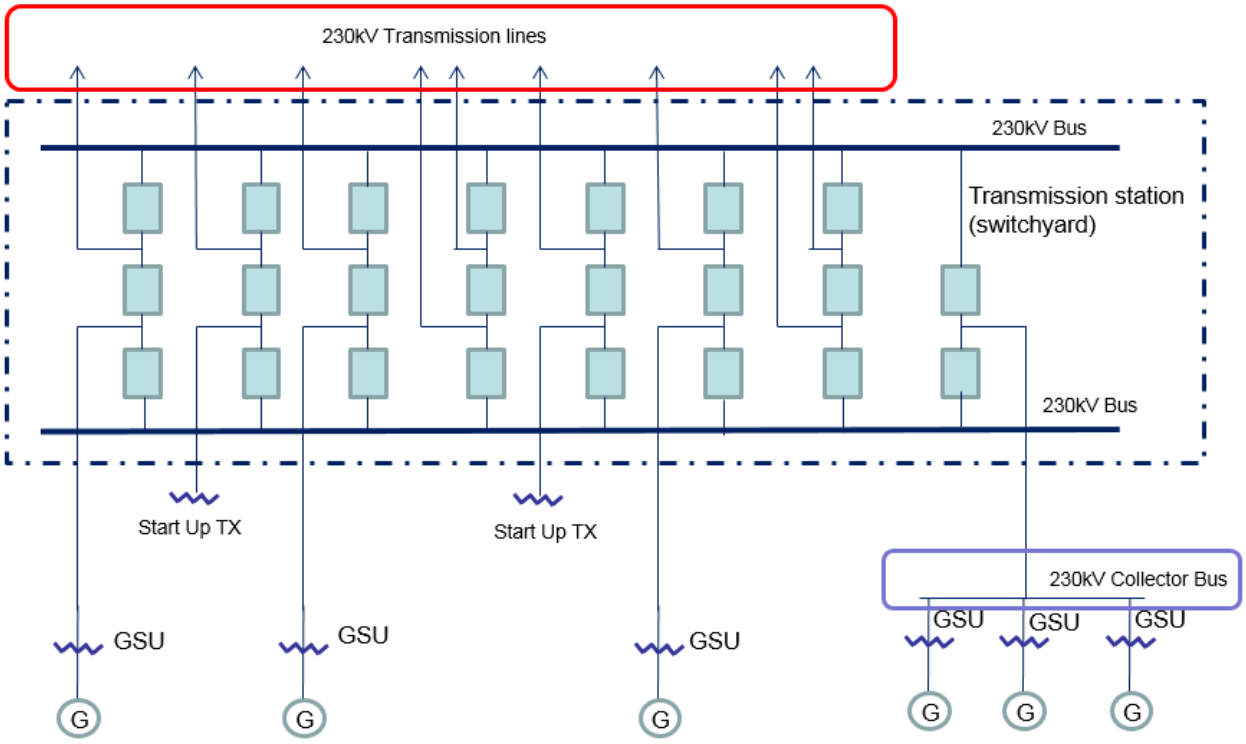
The purpose of Reliability Standard CIP-014~~-1~~ is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014~~-1~~ first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause ~~widespread~~ instability, uncontrolled separation, or Cascading within

an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014~~-1~~. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014~~-1~~, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014~~-1~~ when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014~~-1~~ standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for

the risk assessment and the attributes of what constitutes ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations.~~-~~ Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. A primary control

center “operationally controls” a Transmission station or Transmission substation when the control center’s electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the “verification may occur concurrent with or after the risk assessment performed under Requirement R1.” This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2

is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

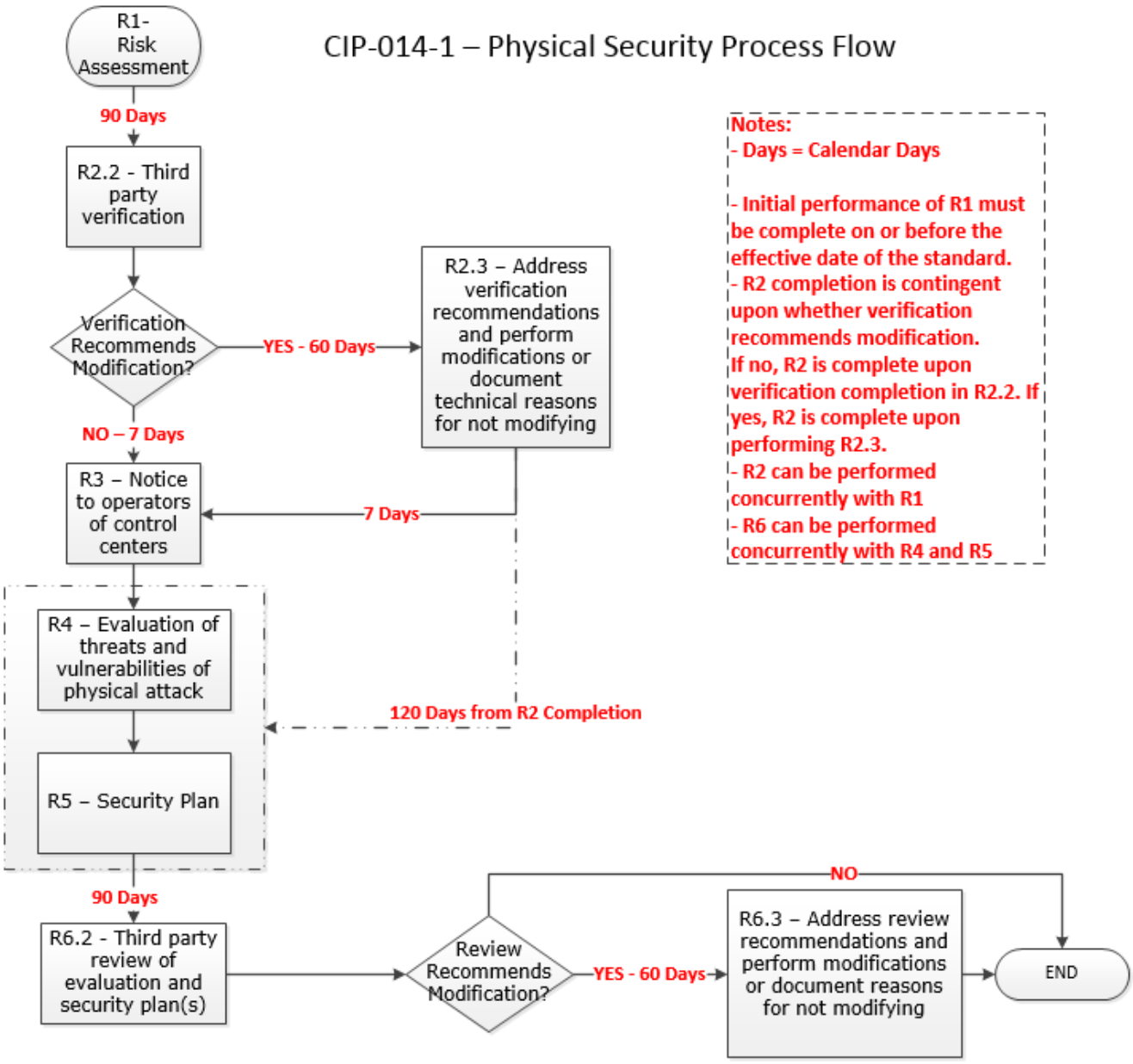
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 in the order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through ~~widespread~~ instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1~~It~~ also meets the portion of the directive ~~from paragraph 11~~ for periodic reevaluation of~~by requiring~~ the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:

This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the

facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:

This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

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Implementation Plan

Physical Security Directives
CIP-014-2

Standards Involved

Approval:

- CIP-014-2 – Physical Security

Retirement:

- CIP-014-1 – Physical Security

Prerequisite Approvals:

N/A

Background

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

Effective Date

CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day after CIP-014-2 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction

Retirement of Existing Standards:

The existing standard, CIP-014-1, shall be retired at midnight of the day immediately prior to the effective date of CIP-014-2 in the particular jurisdiction in which the revised standard is becoming effective.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Transmission Operator

Implementation of CIP-014-1

All aspects of the Implementation Plan for CIP-014-1 will remain applicable to CIP-014-2 and are incorporated here by reference.

Cross References

The Implementation Plan for CIP-014-1 is available here.

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Consideration of Directives

Project 2014-04 - Physical Security Directives

April 16, 2015

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 19. In addition to approving Reliability Standard CIP-014-1, the Commission adopts in part the NOPR proposal directing NERC to develop and submit modifications to the Reliability Standard concerning the use of the term "widespread" in Requirement R1. The Commission determines that the term "widespread" is unclear with respect to the obligations it imposes on applicable entities; how it would be implemented by applicable entities; and how it would be enforced. Accordingly, the Commission directs NERC, pursuant to FPA section 215(d)(5), to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. We direct that NERC submit a responsive	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	The Physical Security Standard Drafting Team (PSSDT) revised CIP-014-1, Physical Security, by removing the term "widespread" from the standard. This was done in the Purpose Statement, Background Section, Requirement R1, the Rationale for Requirement R1 as well as the Guidance and Technical Basis Section of the standard. Additionally, the PSSDT has added the following to the Rationale and guideline and Technical Basis for Requirement R1: "The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
modification within six months from the effective date of this final rule. Paragraph 35: Accordingly, pursuant to FPA section 215(d)(5), the Commission directs NERC to develop a modification to Reliability Standard CIP-014-1 that either removes the term "widespread" from Requirement R1 or, in the alternative, proposes changes that address the Commission's concerns. Further, we direct that NERC submit a responsive modification within six months from the effective date of this final rule. We recognize that certain entities commented on how NERC could modify Reliability Standard CIP-014-1 to address the Commission's stated concerns. However, we conclude that it is appropriate to allow NERC to develop and propose a modification in the first instance.		the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following: • Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6 • NERC EOP-004-2 reporting criteria • Area or magnitude of potential impact" Additionally, the PSSDT revised the Rationale for Requirement R1 as follows: "Requirement R1 also meets the directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an interconnection)."

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 21. With respect to the informational filings proposed in the NOPR, the Commission adopts the proposal to direct NERC to make an informational filing addressing whether Reliability Standard CIP-014-1 provides physical security for all "High Impact" control centers, as that term is defined in Reliability Standard CIP-002-5.1, necessary for the reliable operation of the Bulk-Power System. However, the Commission extends the deadline for that informational filing until two years following the effective date of Reliability Standard CIP-014-1. Paragraph 57. The Commission adopts the NOPR proposal and directs NERC to submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers. The Commission, however, modifies the NOPR proposal and extends the due date for the informational filing to two years following the effective date of Reliability Standard CIP-014-1.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1 and R2 with respect to "High Impact" control centers as that term is defined in Reliability Standard CIP-002-5.1 as that term is defined in Reliability Standard CIP-002-5.1. NERC will submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers within two years following the effective date of Reliability Standard CIP-014-1.

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 44. The Commission, instead, will focus its resources on carrying out compliance and enforcement activities to ensure that critical facilities are identified under Requirement R1. In its comments, NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1, R2 and R3 and will submit to the NERC Board of Trustees, a report three months following implementation of these Requirements concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC will also submit this report to Commission staff.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of ~~Issues and~~ Directives

Project 2014-04 - Physical Security Directives

April 16~~January 27~~, 2015

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 19. In addition to approving Reliability Standard CIP-014-1, the Commission adopts in part the NOPR proposal directing NERC to develop and submit modifications to the Reliability Standard concerning the use of the term "widespread" in Requirement R1. The Commission determines that the term "widespread" is unclear with respect to the obligations it imposes on applicable entities; how it would be implemented by applicable entities; and how it would be enforced. Accordingly, the Commission directs NERC, pursuant to FPA section 215(d)(5), to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. We direct that NERC submit a responsive	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	The Physical Security Standard Drafting Team (PSSDT) revised CIP-014-1, Physical Security, by removing the term "widespread" from the standard. This was done in the Purpose Statement, Background Section, Requirement R1, the Rationale for Requirement R1 as well as the Guidance and Technical Basis Section of the standard. Additionally, the PSSDT has added the following to the Rationale and guideline and Technical Basis for Requirement R1: "The requirement is ~~not to require identification of, and thus,~~ not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
modification within six months from the effective date of this final rule. Paragraph 35: Accordingly, pursuant to FPA section 215(d)(5), the Commission directs NERC to develop a modification to Reliability Standard CIP-014-1 that either removes the term "widespread" from Requirement R1 or, in the alternative, proposes changes that address the Commission's concerns. Further, we direct that NERC submit a responsive modification within six months from the effective date of this final rule. We recognize that certain entities commented on how NERC could modify Reliability Standard CIP-014-1 to address the Commission's stated concerns. However, we conclude that it is appropriate to allow NERC to develop and propose a modification in the first instance.		the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following: • Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6 • NERC EOP-004-2 reporting criteria • Area or magnitude of potential impact" Additionally, the PSSDT revised the Rationale for Requirement R1 as follows: "Requirement R1~~It~~ also meets the ~~portion of the~~ FERC directive ~~from paragraph 11~~ for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment~~)~~ any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an interconnection[A1]~~)~~."

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 21. With respect to the informational filings proposed in the NOPR, the Commission adopts the proposal to direct NERC to make an informational filing addressing whether Reliability Standard CIP-014-1 provides physical security for all "High Impact" control centers, as that term is defined in Reliability Standard CIP-002-5.1, necessary for the reliable operation of the Bulk-Power System. However, the Commission extends the deadline for that informational filing until two years following the effective date of Reliability Standard CIP-014-1. Paragraph 57. The Commission adopts the NOPR proposal and directs NERC to submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers. The Commission, however, modifies the NOPR proposal and extends the due date for the informational filing to two years following the effective date of Reliability Standard CIP-014-1.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1 and R2 with respect to "High Impact" control centers as that term is defined in Reliability Standard CIP-002-5.1 as that term is defined in Reliability Standard CIP-002-5.1. NERC will submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers within two years following the effective date of Reliability Standard CIP-014-1.

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 44. The Commission, instead, will focus its resources on carrying out compliance and enforcement activities to ensure that critical facilities are identified under Requirement R1. In its comments, NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1, R2 and R3 and will submit to the NERC Board of Trustees, a report three months following implementation of these Requirements concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC will also submit this report to Commission staff.

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Project 2014-04 - Physical Security Directives

Mapping Document

Background

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered	Removed the term "widespread" from Requirement R1	**R1.** Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]* **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that		inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]* **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.		Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.
R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with	Retained from previous version	**R2.** Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]* **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience. **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90		after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]* **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience. **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
calendar days following the completion of the Requirement R1 risk assessment. **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation: • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.		calendar days following the completion of the Requirement R1 risk assessment. **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation: • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.		**2.4.** Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.
R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the	Retained from previous version	**R3.** For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]* **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.		primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]* **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.
	Retained from previous version	

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]* **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s); **4.2.** Prior history of attack on similar facilities taking into account the frequency,	Retained from previous version	**R4.** Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]* **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s); **4.2.** Prior history of attack on similar facilities taking into account the frequency,

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
geographic proximity, and severity of past physical security related events; and **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.		geographic proximity, and severity of past physical security related events; and **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.
R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and	Retained from previous version	**R5.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]* **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4. **5.2.** Law enforcement contact and coordination information. **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.		control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]* **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4. **5.2.** Law enforcement contact and coordination information. **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).		**5.4.** Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).
R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*	Retained from previous version	**R6.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: • An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. • An entity or organization approved by the ERO. • A governmental agency with physical security expertise. • An entity or organization with demonstrated law enforcement, government, or military physical security expertise.		**6.1.** Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: • An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. • An entity or organization approved by the ERO. • A governmental agency with physical security expertise. • An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5. **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:		**6.2.** The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5. **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
• Modify its evaluation or security plan(s) consistent with the recommendation; or • Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation. **6.4.** Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.		• Modify its evaluation or security plan(s) consistent with the recommendation; or • Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation. **6.4.** Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

Project 2014-04 Physical Security

VRF and VSL Justifications for CIP-014-2

VRF and VSL Justifications – CIP-014-1, R1	
Proposed VRF	High
NERC VRF Discussion	Initial and subsequent risk assessments identify Transmission stations or Transmission substations that need to be assessed for threats and vulnerabilities and potential physical security measures. Since this is a Requirement in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the risk assessment periodicity and the identification of the primary control center that has operational control of Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-002-5.1 R1, which deals with categorizing cyber systems, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR

VRF and VSL Justifications – CIP-014-1, R1	
	The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.
Proposed Moderate VSL	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.
Proposed High VSL	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission

VRF and VSL Justifications – CIP-014-1, R1	
	substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.
Proposed Severe VSL	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection

VRF and VSL Justifications – CIP-014-1, R1	
	performed a subsequent risk assessment but did so after more than 66 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if the risk assessment is not performed or if the risk assessment is not performed within required intervals.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The VSL is assigned for a single instance of failing to submit perform a risk assessment.

VRF and VSL Justifications – CIP-014-1, R1	
Cumulative Number of Violations	

VRF and VSL Justifications – CIP-014-1, R2	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party verification of initial and subsequent risk assessments provides reinforcement that the risk assessment was performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party verification including entities that may perform the verification, provisions for adding or removing Transmission stations and/or Transmission substations, and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days following completion of Requirement R1; OR

VRF and VSL Justifications – CIP-014-1, R2	
	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.
Proposed Moderate VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.
Proposed High VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by part 2.3.
Proposed Severe VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR

VRF and VSL Justifications – CIP-014-1, R2	
	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party verification is not performed or if the verification is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to have an unaffiliated third party verification performed; or failing to perform the verification within prescribe timelines; or failing to implement procedures to protect information.

VRF and VSL Justifications – CIP-014-1, R3	
Proposed VRF	Lower
NERC VRF Discussion	Notifying the Transmission Operator that it has operational control of a Transmission station or Transmission substation identified in Requirement R1 and verified in Requirement R2 is necessary so that the Transmission Operator may begin performance of subsequent physical security requirements for the primary control center. This is a requirement that is administrative in nature and in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. This justifies a Lower VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the notification of the Transmission Operator regarding the removal of a Transmission station or Transmission substation.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-4 R6, which deals with notifying other entities so that Confirmed Interchange may be implemented, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR

VRF and VSL Justifications – CIP-014-1, R3	
	The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.
Proposed Moderate VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.
Proposed High VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.
Proposed Severe VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR

VRF and VSL Justifications – CIP-014-1, R3	
	The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if notification is not made subject to the conditions of the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to make the appropriate notification.

VRF and VSL Justifications – CIP-014-1, R4	
Proposed VRF	Medium
NERC VRF Discussion	Performing an evaluation of potential threats and vulnerabilities of a physical attack to each of respective Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the evaluation of potential threats and vulnerabilities of a physical attack to Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-007-5 R2, which deals with a patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission

VRF and VSL Justifications – CIP-014-1, R4	
	station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.
Proposed High VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.
Proposed Severe VSL	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failed to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failing to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R5	
Proposed VRF	High
NERC VRF Discussion	Development, implementation and execution of a documented physical security plan(s) that covers applicable Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the physical security plan for applicable Transmission stations, Transmission substations, or primary control centers.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-003-3 R4, which deals with implementing and documenting a program to identify, classify, and protect information associated with Critical Cyber Assets, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR

VRF and VSL Justifications – CIP-014-1, R5	
	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.
Proposed Moderate VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.
Proposed High VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.
Proposed Severe VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1. OR

VRF and VSL Justifications – CIP-014-1, R5	
	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include Parts 5.1 through 5.4 in the plan.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s) or if the responsible entity failed to include any of the Requirement Parts 5.1-5.4.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failing to include any of the Requirement Parts 5.1-5.4.

VRF and VSL Justifications – CIP-014-1, R6	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party review of the threat evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 provides reinforcement that these requirements were performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party review including entities that may perform the review, timelines for completing the review and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR

VRF and VSL Justifications – CIP-014-1, R6	
	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.
Proposed Moderate VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.
Proposed High VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not and modify or document the reason for not modifying the security plan(s) as specified in Part 6.3.
Proposed Severe VSL	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days;

VRF and VSL Justifications – CIP-014-1, R6	
	OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party review is not performed or if the review is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to have an unaffiliated third party review performed; or failing to perform the review within prescribe timelines; or failing to implement procedures to protect information.

VRF and VSL Justifications – CIP-014-1, R6	
on A Single Violation, Not on A Cumulative Number of Violations	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2014-04 Physical Security

VRF and VSL Justifications for CIP-014-2

VRF and VSL Justifications – CIP-014-1, R1	
Proposed VRF	High
NERC VRF Discussion	Initial and subsequent risk assessments identify Transmission stations or Transmission substations that need to be assessed for threats and vulnerabilities and potential physical security measures. Since this is a Requirement in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the risk assessment periodicity and the identification of the primary control center that has operational control of Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-002-5.1 R1, which deals with categorizing cyber systems, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date;

VRF and VSL Justifications – CIP-014-1, R1	
	OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.
Proposed Moderate VSL	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.
Proposed High VSL	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date;

VRF and VSL Justifications – CIP-014-1, R1	
	OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.
Proposed Severe VSL	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk

VRF and VSL Justifications – CIP-014-1, R1	
	assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if the risk assessment is not performed or if the risk assessment is not performed within required intervals.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit perform a risk assessment.

VRF and VSL Justifications – CIP-014-1, R2	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party verification of initial and subsequent risk assessments provides reinforcement that the risk assessment was performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party verification including entities that may perform the verification, provisions for adding or removing Transmission stations and/or Transmission substations, and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days following completion of Requirement R1;

VRF and VSL Justifications – CIP-014-1, R2	
	OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.
Proposed Moderate VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.
Proposed High VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by part 2.3.
Proposed Severe VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party

VRF and VSL Justifications – CIP-014-1, R2	
	verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party verification is not performed or if the verification is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to have an unaffiliated third party verification performed; or failing to perform the verification within prescribe timelines; or failing to implement procedures to protect information.

VRF and VSL Justifications – CIP-014-1, R2	
on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – CIP-014-1, R3	
Proposed VRF	Lower
NERC VRF Discussion	Notifying the Transmission Operator that it has operational control of a Transmission station or Transmission substation identified in Requirement R1 and verified in Requirement R2 is necessary so that the Transmission Operator may begin performance of subsequent physical security requirements for the primary control center. This is a requirement that is administrative in nature and in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. This justifies a Lower VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the notification of the Transmission Operator regarding the removal of a Transmission station or Transmission substation.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-4 R6, which deals with notifying other entities so that Confirmed Interchange may be implemented, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar

VRF and VSL Justifications – CIP-014-1, R3	
	days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.
Proposed Moderate VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.
Proposed High VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.
Proposed Severe VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1.

VRF and VSL Justifications – CIP-014-1, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if notification is not made subject to the conditions of the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to make the appropriate notification.

VRF and VSL Justifications – CIP-014-1, R4	
Proposed VRF	Medium
NERC VRF Discussion	Performing an evaluation of potential threats and vulnerabilities of a physical attack to each of respective Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the evaluation of potential threats and vulnerabilities of a physical attack to Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-007-5 R2, which deals with a patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – CIP-014-1, R4	
Proposed Moderate VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.
Proposed High VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.
Proposed Severe VSL	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failed to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R4	
Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failing to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R5	
Proposed VRF	High
NERC VRF Discussion	Development, implementation and execution of a documented physical security plan(s) that covers applicable Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the physical security plan for applicable Transmission stations, Transmission substations, or primary control centers.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-003-3 R4, which deals with implementing and documenting a program to identify, classify, and protect information associated with Critical Cyber Assets, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2;

VRF and VSL Justifications – CIP-014-1, R5	
	OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.
Proposed Moderate VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.
Proposed High VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.
Proposed Severe VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission

VRF and VSL Justifications – CIP-014-1, R5	
	station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include Parts 5.1 through 5.4 in the plan.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s) or if the responsible entity failed to include any of the Requirement Parts 5.1-5.4.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level	The VSL is assigned for a single instance of failing to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and

VRF and VSL Justifications – CIP-014-1, R5	
Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	primary control center(s) or failing to include any of the Requirement Parts 5.1-5.4.

VRF and VSL Justifications – CIP-014-1, R6	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party review of the threat evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 provides reinforcement that these requirements were performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party review including entities that may perform the review, timelines for completing the review and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days;

VRF and VSL Justifications – CIP-014-1, R6	
	OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.
Proposed Moderate VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.
Proposed High VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not and modify or document the reason for not modifying the security plan(s) as specified in Part 6.3.
Proposed Severe VSL	The Responsible Entity failed to have an unaffiliated third party

VRF and VSL Justifications – CIP-014-1, R6	
	review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4~~3~~.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party review is not performed or if the review is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R6	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to have an unaffiliated third party review performed; or failing to perform the review within prescribe timelines; or failing to implement procedures to protect information.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2014-04 Physical Security
CIP-014-2

Final Ballot Open through April 29, 2015

Now Available

A final ballot for **CIP-014-2 – Physical Security** is open through **8 p.m. Eastern, Wednesday, April 29, 2015.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a vote. All ballot pool members may change their previously cast votes. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard here. If you experience any difficulties in using the Standards Commenting & Balloting System, contact Wendy Muller.

Next Steps

Voting results for the standard will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities**.**

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Stephen Crutchfield (via email), or at (609) 651-9455.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2014-04 Physical Security
CIP-014-2

Final Ballot Results

Now Available

A final ballot for **CIP-014-2 – Physical Security** concluded at **8 p.m. Eastern, Wednesday, April 29, 2015**.

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below and the Ballot Results page provides a link to the detailed results for the ballot.

Quorum / Approval
92.00% / 92.35%

Next Steps
The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Stephen Crutchfield (via email), or at (609) 651-9455.

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BALLOT RESULTS

Ballot Name: 2014-04 Physical Security CIP-014-2 FN 2 ST
Voting Start Date: 4/20/2015 8:55:54 AM
Voting End Date: 4/29/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 276
Total Ballot Pool: 300
Quorum: 92
Weighted Segment Value: 92.35

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	82	1	66	0.88	9	0.12	0	2	5
Segment: 2	9	0.7	6	0.6	1	0.1	0	1	1
Segment: 3	74	1	62	0.954	3	0.046	0	1	8
Segment: 4	21	1	16	0.889	2	0.111	0	2	1
Segment: 5	62	1	47	0.922	4	0.078	0	4	7
Segment: 6	40	1	38	0.95	2	0.05	0	0	0
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	2	0.1	1	0.1	0	0	0	0	1

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Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	300	6.6	244	6.095	21	0.505	0	11	24

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	ATCO Electric	David Downey		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican	Terry Harbour		Affirmative	N/A

	Energy Co.				
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash	Candace Marshall	Affirmative	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Matt Stryker	Affirmative	N/A
1	Great Plains Energy -	Daniel Gibson		Affirmative	N/A

	Kansas City Power and Light Co.				
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	Iberdrola - Central Maine Power Company	Joe Turano		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Negative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		Negative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	NextEra Energy -	Mike ONeil		Affirmative	N/A

	Florida Power and Light Co.				
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Denise Lietz		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A

1	SaskPower	Wayne Guttormson		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison		Negative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Negative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		Affirmative	N/A
1	Xcel Energy, Inc.	Greg Pieper		Affirmative	N/A
2	BC Hydro and Power	Venkataramakrishnan		Affirmative	N/A

	Authority	Vinnakota			
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Abstain	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Matthew Goldberg	Michael Puscas	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry Bllke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Sarah Kist		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A

3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Central Hudson Gas & Electric Corp.	James Mccloskey		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Bill Hughes	Mary Downey	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	Fayetteville Public Works Commission	Allen Wallace		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart		Affirmative	N/A
3	Florida Keys Electric Cooperative Assoc.	Tom Anthony		None	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power	Joshua Bach		None	N/A

	and Light Co.				
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Greg LeGrave		Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northeast Utilities	Mark Kenny		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and	Donald Hargrove		Affirmative	N/A

	Electric Co.				
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Terry Baker		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric	John Williams		Negative	N/A

	(City of Tallahassee, FL)				
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	We Energies - Wisconsin Electric Power Marketing	Jim Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Mary Downey	Affirmative	N/A
4	City of Winter Park	Mark Brown		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Abstain	N/A
4	Integrys Energy Group, Inc. - Wisconsin Public	Christopher Plante		Abstain	N/A

	Service Corporation				
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Negative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Keith Morisette		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	brian robinson	Negative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Scott Takinen		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A

5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Kaleb Brimhall		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Golden Spread Electric Cooperative, Inc.	Chip Koloini		Abstain	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Brett Holland		Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	Integrys Energy	Scott Johnson		Abstain	N/A

	Group, Inc. - Wisconsin Public Service Corporation				
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Liberty Electric Power LLC	Daniel Duff		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power	Christopher Wood		Affirmative	N/A

	Authority				
5	Public Utility District No. 1 of Douglas County	Curt Wilkins		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Negative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	U.S. Army Corps of Engineers	Melissa Kurtz		None	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Negative	N/A
5	We Energies - Wisconsin Electric Power Co.	Linda Horn		Affirmative	N/A

5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Randy Young		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Brenda Anderson		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A

6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Seattle City Light	Dennis Sismaet		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities	Rick Applegate		Affirmative	N/A

	(Tacoma, WA)				
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
7	Siemens - Siemens PTI	Frank McElvain		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	National Association of Regulatory Utility Commissioners	Jerry Maio		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Exhibit G

Mapping Document

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2014-04 - Physical Security Directives

Mapping Document

Background

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered	Removed the term "widespread" from Requirement R1	**R1.** Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]* **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that		inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]* **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.		Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.
R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with	Retained from previous version	**R2.** Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]* **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience. **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90		after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]* **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience. **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
calendar days following the completion of the Requirement R1 risk assessment. **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation: • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.		calendar days following the completion of the Requirement R1 risk assessment. **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation: • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.		**2.4.** Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.
R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the	Retained from previous version	**R3.** For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]* **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.		primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]* **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.
	Retained from previous version	

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]* **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s); **4.2.** Prior history of attack on similar facilities taking into account the frequency,	Retained from previous version	**R4.** Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]* **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s); **4.2.** Prior history of attack on similar facilities taking into account the frequency,

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
geographic proximity, and severity of past physical security related events; and **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.		geographic proximity, and severity of past physical security related events; and **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.
R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and	Retained from previous version	**R5.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]* **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4. **5.2.** Law enforcement contact and coordination information. **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.		control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]* **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4. **5.2.** Law enforcement contact and coordination information. **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).		**5.4.** Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).
R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*	Retained from previous version	**R6.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: • An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. • An entity or organization approved by the ERO. • A governmental agency with physical security expertise. • An entity or organization with demonstrated law enforcement, government, or military physical security expertise.		**6.1.** Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: • An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. • An entity or organization approved by the ERO. • A governmental agency with physical security expertise. • An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5. **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:		**6.2.** The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5. **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
• Modify its evaluation or security plan(s) consistent with the recommendation; or • Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation. **6.4.** Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.		• Modify its evaluation or security plan(s) consistent with the recommendation; or • Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation. **6.4.** Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

Exhibit H

Standards Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2014-04 Physical Security Standards Drafting Team Roster

Name and Title	Company and Address	Contact Info	Bio
Susan Ivey Chair	2301 Market St. Philadelphia, PA 19103	215-841-4706 SusanO'Brien.Ivey@exeloncorp.com	Susan Ivey is Vice President of Transmission Strategy & Compliance at Exelon and is responsible for oversight of the electric transmission systems of the Exelon Utilities of BGE, ComEd and PECO located in Baltimore, Chicago and Philadelphia, respectively. She coordinates the efforts for electric transmission operations and long-term planning for all three companies, and manages the interface with regulatory authorities and all transmission interconnected third parties. Ms. Ivey oversees and administers the NERC Compliance Program for Exelon. Ms. Ivey also leads the coordination of physical security practices across the Exelon Utilities to ensure alignment of strategies and programs for addressing security risks associated with the electric and gas businesses.
Lou Oberski Vice-Chair	Dominion Resources Services, Inc.	804-819-2837 Lou.Oberski@dom.com	Lou Oberski is Managing Director of Regulation and NERC Compliance Policy for Dominion Resources Services, Inc. He is responsible for administration of all aspects of Dominion's corporate NERC compliance assurance programs and oversees Dominion's

	120 Tredegar St Richmond, VA 23219		involvement at NERC and its sub-regions as well as FERC and RTO policy coordination for Dominion at PJM, ISO-New England and the MidContinent ISO. Prior to his current position, his career at Dominion covered increasing management responsibilities in transmission engineering, operations, planning and maintenance. The most recent 10 years have focused on developing, establishing and coordinating NERC and RTO policy at Dominion with a particular emphasis on generation supplier policy at NERC and RTOs. Mr. Oberski is a member of the North American Energy Standards Board, Board of Directors and past chair of its Executive Committee. He is also a member of EEI's Reliability Executive Advisory Committee, the SERC Board of Directors and SERC Board Executive Committee. Mr. Oberski has been employed by Dominion for 30 years and holds a bachelor's degree in electrical engineering from Western Michigan University.
John Breckenridge	KCP&L 1200 Main Street 18th Floor KCMO 64106	816-654-1725 john.breckenridge @kcpl.com	John Breckenridge is the Senior Manager of Corporate Security for Kansas City Power & Light based in Kansas City, MO. In his current capacity, he directs the overall Corporate Security function to ensure security operations are in compliance with

			legal, regulatory, and company requirements. Corporate Security responsibilities include physical security, investigations, guard force management, protection operations, law enforcement liaison, enterprise-wide crisis management and business continuity planning. To be effective, Mr. Breckenridge uses his 25 plus years of military, criminal justice and industrial security experience to work with each functional department and business unit. Mr. Breckenridge began his career while in the US Army, where he was instrumental in supporting many special security operations throughout the US and in many countries, especially during his assignment in Europe. In addition to his eight-year career in the military, Mr. Breckenridge worked for six years in the Jackson County, MO. criminal justice system. During this time, he specialized in security systems, close protection operations and special event security functions first with the Department of Corrections and then in conjunction with the Jackson County Courts. From 1993 until 2008, Mr. Breckenridge was the Director of Security and Chief Security Officer for

			Aquila Energy until Aquila was purchased by Kansas City Power & Light. Mr. Breckenridge is Board Certified in Security Management as a Certified Protection Professional, holds a BLA degree and a degree with an emphasis in Criminal Justice, is a Licensed Private Investigator and an active member of several security related professional organizations. Mr. Breckenridge has been featured as a Guest Lecturer for successful business approaches to security issues and has also been featured in several trade and regional publications.
Ross Johnson	Capital Power	780-405-5542 rjohnson@capitalpower.com	Ross Johnson, CPP is the Senior Manager of Security and Contingency Planning for Capital Power. He served in the Canadian Forces as an infantry and intelligence officer for 24 years. Since leaving the service in 2001, Mr. Johnson has been employed in several security-related leadership positions in aviation security, the offshore oil industry, and the electricity sector. Prior to joining Capital Power in 2009, he was the Director of Security and Contingency Planning with EPCOR Utilities. Mr. Johnson is the author of Antiterrorism Planning and Threat Response, a book on the prevention of

			terrorist attacks. (Click here for a recent review in the ASIS publication 'Security Dynamics.) Mr. Johnson is a member of the NERC Critical Infrastructure Protection Committee, where he sits on the Executive Committee. He is also Chair of the Committee's Physical Security Working Group, and the leader of the Physical Security Roundtable Group. He is Chair of the Canadian Electricity Association's Security and Infrastructure Protection Committee, and Chair of ASIS International's Petrochemical, Chemical, and Extractive Industries Security Council. Mr. Johnson has a Baccalaureate in Military Arts and Sciences with Distinction, and is board-certified in security management by ASIS International.
Kathleen Judge	National Grid 939 Southbridge Street, Worcester, MA 01610	508-860-6040 Kathleen.judge@nationalgrid.com	Kathy Judge is Director of Risk and Compliance for Security at National Grid, where she has worked for 25+ years. Ms. Judge is responsible for managing National Grid's strategies and best practices required to protect energy delivery facilities in accordance with governing security regulations in the US. As part of this she is actively engaged with state and federal regulatory authorities to shape policies and procedures. For example, at the federal level she works with the Infrastructure Security Compliance Division of DHS, the United States Coast Guard and

			the Pipeline Security Division of the Transportation Security Administration. Ms. Judge was also the chair of the American Gas Association Security Committee and currently serves as an AGA representative on the Oil & Natural Gas Sector Coordinating Council. She is also actively involved in the EEI Security Committee and serves on the Executive Steering Committee for the Long Island Sound Area Maritime Security Committee. In prior roles, Ms. Judge was responsible for, and a key member on, delivering Company's business plan for a deregulated energy market, serving as the strategic and operational expert on electricity restructuring for Massachusetts, Rhode Island, New Hampshire and New York. She was also an active member of the North American Energy Standards Board Retail Electric Quadrant, developing model business practices for deregulated marketplaces. Leading up to this, she was a key developer and implementer of an award winning renewable energy program in Massachusetts and Rhode Island. Ms. Judge holds a Master of Business Administration degree from Nichols College.

Mike O'Neil	Florida Power & Light 700 Universe Blvd., Juno Beach, Fl. 33408	561-904-3503 mco0hwz@fpl.com	Mike O'Neil is Director of Power Delivery Compliance & Regulatory. He is responsible for business unit execution compliance to transmission based FERC requirements for FPL and NERC transmission reliability standards for FPL and NEER facilities throughout the country.
Stephen Pelcher	Santee Cooper One Riverwood Drive Moncks Corner, SC 29461	843-761-4016 srpelche@santeecooper.com	Stephen Pelcher is Deputy General Counsel Nuclear and Regulatory Compliance at Santee Cooper. Mr. Pelcher joined Santee Cooper in 1996. Prior to working for Santee Cooper, he was Senior Attorney for Duquesne Light Company in Pittsburgh (1990 to 1996). Mr. Pelcher has been a practicing attorney for more than 31 years and has worked in the electric utility industry for 24 years. Among other duties, Mr. Pelcher is the lead Santee Cooper company attorney in all matters within the jurisdiction of the FERC under Part II of the Federal Power Act; the lead company attorney relating to interpretation of requirements embedded within standards established by NERC under Section 215 of the Federal Power Act and current Chair of Santee Cooper's internal Reliability Standards Compliance Coordination Committee. Mr. Pelcher has a Bachelor of Arts degree in Philosophy from the University of Pittsburgh, College of Arts and Sciences; a Juris Doctor from the

			University of Pittsburgh, School of Law; and an LL.M (Taxation) from the Dickinson School of Law, Pennsylvania State University.
John Pespisa	Southern California Edison 2244 Walnut Grove Ave. Rosemead, Ca 91770	626-688-6291 John.pespisa@sce.com	John Pespisa is Director of SCE's NERC Compliance program and Acting Director of SCE's Security Technology & Compliance group. Mr. Pespisa started his career with Southern California Edison in 1987, starting in transmission operations and electrical substations. Since then he has worked in positions of increasing responsibility including operation of SCE's bulk electric and distribution systems, and supervisory positions at SCE's Energy Control Center, including Manager of short term power marketing, and Manager of Real-Time Power Operations. In 2011, he moved to his current position as the Director of SCE's NERC Compliance Program In his current role he oversees SCE's compliance with federal Reliability Standards, which have been promulgated to ensure the safe, reliable operation of the power grid, and to protect the grid's critical infrastructure against cyber threats. Mr. Pespisa is a graduate of Cal State Los Angeles and hold degrees in Electrical Engineering and Business Management.
Robert Rhodes	Southwest Power Pool	501-614-3241 rrhodes@spp.org	Robert Rhodes is the Manager, Reliability Standards at Southwest Power Pool (SPP) where he has been

	201 Worthen Drive Little Rock, AR 72223		employed since 2000. In his previous role at SPP he was Manager, Reliability Coordination for over 10 years. Prior to joining SPP, Mr. Rhodes worked at Progress Energy (Carolina Power & Light Company) in Raleigh, NC for over 26 years in various positions in transmission maintenance, operations and planning. In his current capacity, Mr. Rhodes works with SPP members, SPP staff and other industry experts to ensure that reliability standards necessary to maintain a reliable bulk electric system are in place. He coordinates SPP members and registered entities in the development, refinement, maintenance, communication, training and implementation of national and regional reliability standards and policies. Mr. Rhodes is active at NERC currently serving on the Operating Reliability Subcommittee (ORS), the ORS Executive Committee, the Resources Subcommittee, the Standards Committee Process Subcommittee, the Reliability Coordination Standard Drafting Team, the Operating Personnel Communications Protocols Standard Drafting Team and the TOP/IRO Revisions Standard Drafting Team. He has previously served on the Reliability Coordinator Working Group, the Interchange Distribution Calculator Working Group and was Vice Chair of the Distribution Factor Working Group. Additionally, he has served on committees,

			working groups and task forces in SPP, SERC and VACAR. Mr. Rhodes received an Associate in Science degree from Rockingham Community College in 1970, a Bachelor of Science degree in Electrical Engineering from North Carolina State University in 1972 and a Master of Engineering degree from Rensselaer Polytechnic Institute in 1974. He is a member of Tau Beta Pi, Eta Kappa Nu, Order of the Engineer, the Institute of Electrical and Electronics Engineers and its Power Engineering Society and the National Society of Professional Engineers. He is a NERC Certified System Operator (Reliability) and is a registered professional engineer in the State of North Carolina.

Allan Wick	Tri-State Generation & Transmission Association, Inc. 1100 W. 116th Ave., Westminster, CO 80234	303-254-3341 awick@tristategt.org	Allan Wick is a 30 year security executive, 13 in the energy sector with a comprehensive industry perspective after working for an investor owned utility, independent system operator and now at a cooperative generation and transmission company - where he serves as their Enterprise Security Manager & Chief Security Officer. He is a member of the ASIS International Utilities Security Council and the WECC Physical Security Working Group since 2005. He also served for six years on the ASIS International Certification Board of Directors. Mr. Wick has designed and implemented enterprise-wide physical security programs for three different organizations, served as a drafting team member for five ANSI standards, and has authored a number of security related magazine articles and white papers. Mr. Wick received his MBA from Webster University and holds multiple security and business continuity certifications, including CPP, PSP, CBCP, CFE, and PCI.
Manho Yeung	Pacific Gas and Electric Company Mail Code N9G, P.O. Box 770000	415-973-7649 MxY6@pge.com	Manho Yeung is Senior Director, System Planning and Reliability, for Pacific Gas and Electric Company and is responsible for electric transmission and distribution planning, asset and risk management and reliability

	San Francisco, California, 94177		improvements. Manho oversees PG&E's capital investment plan in expanding, upgrading and modernizing its 18,500 miles of electric transmission lines, 850 substations, and 140,000 miles of distribution lines. Mr. Yeung has been with Pacific Gas and Electric Company since 1980 and has over 30 years of energy policy, electric generation planning, electric T&D planning, asset and risk management, project management, engineering, and operations experience. Mr. Yeung received his Bachelor of Science degree in electric engineering from the Georgia Institute of Technology, and a Master of Science degree in electric engineering from the Santa Clara University. He is a registered professional electric engineer in the State of California.
Stephen Crutchfield Senior Standards Developer	North American Electric Reliability Corporation 3353 Peachtree Road, NE, Suite 600 - North Tower Atlanta, GA 30326	609-651-9455 Stephen.crutchfield@nerc.net	Stephen Crutchfield is the lead NERC Staff Senior Standards Developer for Project 2014-04, Physical Security. Stephen began his career with NERC in May 2007. Prior to joining NERC, he was a Project Manager with Shaw Energy Delivery Services, managing engineering and construction projects in the substation and transmission line fields. Mr. Crutchfield's background also includes experience

			with PJM as Manager of RTO Integration, working on the operations and markets integration of new members (AEP, ComEd, Dayton, Dominion and Duquesne) into PJM and southern seams operations issues with Progress Energy, Duke and TVA. He also helped lead the team that was developing GridSouth in the dual roles of Organization Architect and Manager of Customer Support. Prior to GridSouth, Stephen was the Manager of Power System Operations Training at Progress Energy where he spent over 10 years training System Operators and Engineers. Overall, Stephen was with Progress Energy for 16 years. Mr. Crutchfield received his Bachelor of Arts in Physics from the University of Virginia and Masters of Science in Electrical Engineering from North Carolina State University. He holds a Master of Science in Management degree, also from North Carolina State University. He is also a member of the Institute of Electrical and Electronic Engineers and the Power and Energy Society.
Steven Noess Director of Compliance Assurance	North American Electric Reliability Corporation	404-217-9691 steven.noess@nerc.net	Steven Noess is Director of Compliance Assurance at the North American Electric Reliability Corporation (NERC) in Atlanta, GA, and has been employed by NERC since 2011.

	3353 Peachtree Road, NE, Suite 600 - North Tower Atlanta, GA 30326		Prior to joining NERC, Mr. Noess was an attorney at the Minnesota Legislature. Before becoming an attorney, Steven was an officer in the United States Army. Mr. Noess has a bachelor's of science degree from the U.S. Military Academy, West Point, NY, and a law degree from the University of Minnesota Law School.
Mark Olson Senior Standards Developer	North American Electric Reliability Corporation 3353 Peachtree Road, NE, Suite 600 - North Tower Atlanta, GA 30326	404-446-9760 Mark.olson@nerc.net	Mark Olson is a Senior Standards Developer at the North American Electric Reliability Corporation (NERC), and has been employed by NERC since 2012. Previously he was a career officer in the U.S. Navy where he served in various positions related to the operations and management of surface ships and naval personnel. Mr. Olsen has a master's degree in electrical engineering from the Naval Postgraduate School and a bachelor's degree from the U.S. Naval Academy.
Brian Harrell Director, ES-ISAC Operations and Deputy Director of the ES-ISAC	Electricity Sector Information Sharing and Analysis Center North American Electric Reliability Corporation	202-400-3003 office | 609-651-0671 (c) Brian.Harrell@nerc.net	Brian Harrell is the Director, ES-ISAC Operations for the Electricity Sector Information Sharing and Analysis Center (ES-ISAC) and Deputy Director of the ES-ISAC at the North American Electric Reliability Corporation (NERC), joining NERC in August 2010. In this capacity he is responsible for managing situational awareness, incident management, and

	1325 G Street NW, Suite 600 Washington, DC 20005		security coordination for the electricity sector through timely, reliable and secure information exchange. Mr. Harrell has 18 years of experience in the security industry serving in organizations such as law enforcement, military, and corporate security, among others. Mr. Harrell is formerly the NERC Director of Critical Infrastructure Protection Programs, as well as the CIP Manager for the SERC Reliability Corporation, where he oversaw electricity security related matters. Prior to joining SERC, Brian was the Sector Security Specialist for the Infrastructure Security Compliance Division at the U.S. Department of Homeland Security (DHS). Mr. Harrell specialized in securing high risk facilities and Continuity of Operations (COOP) for DHS. Brian also served in the US Marine Corps as an Anti-Terrorism and Force Protection Instructor.
Bob Canada Manager, Physical Security	North American Electric Reliability Corporation 3353 Peachtree Road, NE, Suite 600 - North Tower Atlanta, GA 30326	404-446-9709 bob.canada@nerc.net	Bob Canada currently serves as Manager, Physical Security. In this role, he will participates in the Physical Security Standard implementation effort with the Standards-led team at NERC and continues to support the Critical Infrastructure Protection Committee (CIPC) as staff support to the Physical Security Subcommittee and its working groups.

			Mr. Canada was previously employed in the electric industry for 32 years with Southern Company in various roles with corporate security and was Manager of Corporate Security at Georgia Power Company from March 1995 - December 2002. His responsibilities included corporate and internal investigations, physical security of employees and corporate assets. He also directed alarm systems design and installation as well and was responsible for the overall corporate response for security at Georgia Power Co. M. Canada directed the Georgia Power and Southern Company Security Planning for the Atlanta Olympic Games. He was responsible for the development of the corporate security plan along with the implementation and daily operations included physical security of the transmission and distribution facilities supporting the Olympic venues, monitoring the protective countermeasures in place, consulting with Federal, State and Local Law Enforcement Agencies to protect the State, Metropolitan and Atlanta Electrical Infrastructure. Mr. Canada served two terms for the Southeastern Reliability Council (SERC) as the first Chairman of the Critical Infrastructure Protection Committee and represented SERC on the North American Electric

			Reliability Corporation's (NERC) Critical Infrastructure Committee (CIPC) as the Physical Security voting member. Subsequently, he was elected by the CIPC as a Vice Chair for four terms. Mr. Canada received his Bachelor's from West Georgia State University and his Juris Doctorate from Woodrow Wilson College of Law.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

June 2, 2015

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***North American Electric Reliability Corporation***
Request for Approval of Amended Compliance and Certification Committee Charter
Docket No. RR15-___-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC")[1] hereby submits for Federal Energy Regulatory Commission ("FERC" or "Commission") approval the proposed amended Compliance and Certification Committee ("CCC") Charter. This filing consists of this transmittal letter; Attachment 1, which contains a clean version of the proposed amendments to the CCC Charter; and Attachment 2, which contains a redlined version of the proposed amendments.

Proposed Amendments

The proposed amendments to the CCC Charter were made to improve the clarity and accuracy of the document. Specifically, the proposed amendments correct references to the NERC Rules of Procedure and change references to NERC titles to reflect organizational changes at NERC.

[1] NERC is the Commission-certified electric reliability organization responsible for the development and enforcement of mandatory Reliability Standards. *See North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

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FERC originally approved the CCC Charter in June 2007 in an Order on Compliance Filing,[2] and approved a revised CCC Charter in June 2010.[3] In accordance with this prior practice, NERC is submitting these revisions to the charter for FERC approval. The NERC Board of Trustees approved the revised CCC Charter on May 7, 2015. NERC notes that the CCC Charter is not part of NERC's Bylaws or Rules of Procedure and therefore may not require Commission approval. NERC respectfully requests Commission guidance on the need to file amendments to the CCC Charter with the Commission for approval.

Communications

Please address any communications concerning this filing to the persons listed below and place their names on the Commission's official service list:

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[2] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,248, *order on compliance filing*, 121 FERC ¶ 61,033 (2007).

[3] *See North American Electric Reliability Corp.*, Docket No. RR10-8-000 (June 10, 2010) (delegated letter order) (accepting NERC filing of amendments to the NERC Rules of Procedure and CCC Charter).

Conclusion

NERC respectfully requests that the Commission approve the proposed amended CCC Charter and provide guidance as to whether future CCC Charter amendments require Commission approval.

NERC thanks the Commission for its consideration of this filing. Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ _____
Teresina A. Stasko
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Counsel for North American Electric Reliability Corporation

June 2, 2015

Attachment 1

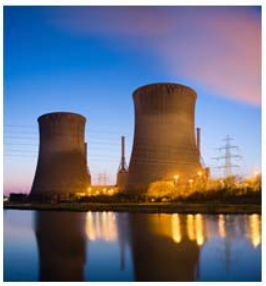
Clean version of the proposed amendments to the CCC Charter

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance and Certification Committee Charter

May 7, 2015

RELIABILITY | ACCOUNTABILITY



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Mission

In the capacity of a North American Electric Reliability Corporation (NERC) Board of Trustees (Board)-appointed stakeholder committee serving and reporting directly to the NERC Board, the Compliance and Certification Committee (CCC) will engage with, support, and advise the NERC Board and NERC regarding all facets of the NERC Compliance Monitoring and Enforcement Program (Compliance and Enforcement program), Organization Registration program (Registration program), and Organization Certification program (Certification program). As a committee providing support and advice but otherwise independent of the execution of these programs, the CCC will monitor NERC's adherence to the Rules of Procedure (ROP) for these programs. Also and in a similar manner, as a committee independent of the Reliability Standards development process, the CCC will be the body responsible for monitoring NERC's adherence to the (ROP) regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Standards process as defined in the appeals section of the Standard Processes Manual. The CCC is also responsible for establishing and implementing a program to monitor NERC's compliance with the Reliability Standards that apply to NERC.

Compliance and Certification Committee Functions

To fulfill its mission, the CCC performs the following functions:

1. Organizes and conducts committee meetings directly with NERC staff regarding all facets of the Compliance and Enforcement, Registration, and Certification programs;[1]
2. Provides comments and recommendations to the NERC Board and NERC staff;
3. Provides comments to NERC with respect to stakeholders' perception of the policies, practices, and effectiveness of the Compliance and Enforcement program, Registration program, and Certification program;
4. Recommends revisions of the electric reliability organization (ERO) ROP related to the Compliance and Enforcement program, Registration program, and Certification program to the NERC Board;
5. Establishes and implements programs to monitor:[2]
    a. NERC's adherence to Section 405 for Compliance Monitoring and Enforcement, including but not limited to the uniform CMEP (Appendix 4C) and the Sanction Guidelines (Appendix 4B).
    b. NERC's adherence to Section 506 for Organization Registration and Certification, including but not limited to the Organization Registration and Certification Manual (Appendix 5A).
    c. NERC's adherence to Section 300 of the ROP regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Reliability Standards process as defined in the appeals section of the Reliability Standards Development Procedure. Committee members who have participated in the development process for a particular Reliability Standard shall not participate in the committee's monitoring of that process.
    d. NERC's compliance with the Reliability Standards that apply to NERC.
6. Serves as the hearing body for any contest regarding findings of or penalties or sanctions for violation(s) of Reliability Standard(s) where NERC is directly monitoring the entity for compliance with those standards (registered entity by agreement with a Regional Entity or absent a delegation agreement; the Region itself where approved standards are applicable to the Region) as described in Section 408 of the NERC ROP;
7. As directed by the NERC Board, serves as the mediator for any disagreements between NERC and the Regional Entities concerning NERC performance audits of Regional Entities' compliance programs. When directed by the Board to serve as mediator, the committee chair will appoint three disinterested members of the committee to meet with representatives of NERC and the Regional Entity to attempt to resolve the matter.
8. Actively supports the Standards Committee in the development of new and revised standards by providing a pool of qualified compliance oriented personnel for participation in the compliance administration element phase of the standards development process;
9. Provides assistance to NERC and the Regional Entities to implement the Compliance and Enforcement, Registration, and Certification programs; and

[1] Meetings are conducted under Section 4 of this Charter.

[2] Monitoring by the CCC is ongoing and does not preclude, interfere with or replace, in whole or in part, the NERC Board's responsibility to conduct and provide such reviews of these programs as required by Federal Energy Regulatory Commission (the Commission) regulations, 18 C.F.R. § 39.3.c: "The Electric Reliability Organization shall submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter."

10. Undertakes assignments from the Board or the Board's Compliance Committee related to compliance and enforcement, organization registration, organization certification, and standards development.

Membership

Goals

The CCC provides for balanced discussion, commentary, and recommendations on compliance issues by bringing together a wide diversity of opinions and perspectives from NERC member sector experts who have particular familiarity, knowledge, and experience in the area of compliance and NERC Standards and Regional Standards.

Appointment and Terms of Service

Members are appointed to the committee by the NERC Board and serve on the committee at the pleasure of the Board. Member terms are the lesser of three years from appointment or interim approval (Section 5.b), replacement, or removal by the Board. Members may be reappointed at the conclusion of a term. There is no limitation on the number of times a member may be reappointed. A member may be recommended to the Board for reappointment by the Nominating Subcommittee by self- nomination. To the extent practicable, member terms will be staggered such that approximately one-third of the committee is subject to reappointment or replacement each year.

Qualifications

Individuals deemed qualified to serve on the committee will generally include senior-level industry experts who have particular familiarity, knowledge, and experience in the area of compliance, compliance enforcement, compliance administration and management, organization responsibilities and registration, organization certification, and NERC Standards and Regional Standards. These individuals should be involved with internal compliance programs within their respective organizations.

Expectations

Committee members are expected to represent the interests of the sector they represent to the best of their ability and judgment. In addition to the duties, rights, and privileges described elsewhere in this charter, committee members will:

1. Act consistently during meetings with the procedures in this manual and Robert's Rules of Order;
2. Demonstrate and provide knowledge and expertise in support of committee activities;
3. Adjudicate in a fair and unbiased manner that meets applicable legal and due process requirements when participating in hearing procedures conducted under the NERC ROP Section 408;
4. Solicit comments and opinions from constituents and groups of constituents or trade organizations represented by the member and convey them to the committee;
5. Respond promptly to all committee requests, including requests for reviews, comments, and votes on issues before the committee;
6. Arrange for a proxy to attend and vote at committee meetings in the member's absence; and
7. Respond promptly to all requests to register for committee meetings.

Representation

The membership structure of the CCC will be modeled upon the membership structure of the NERC Member Representatives Committee (MRC) as described in NERC's Bylaws (the Bylaws) Article VIII Section 2 [see Attachment A]. This should produce a committee that has an appropriate balance of entities subject to compliance with the NERC Reliability Standards and NERC's Compliance and Enforcement program, and others affected by the Standards and the Compliance and Enforcement program.

Regional Entities

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate one member to the committee. In aggregate, the sector will have voting strength equivalent to two members. The voting weight of each Regional member's vote will be set such that the sum of the weight of all available Regional members' votes is two votes.

Canadian Representation

The committee structure will include representation by Canadians as laid out in Article VIII Section 4 of the Bylaws.

NERC Membership

Users, owners, and operators of the bulk power system are subject to the Compliance, Registration, and Certification programs regardless of whether they are NERC members. It is expected that committee members will generally be from organizations who are NERC members; however, committee members may be non-members of NERC who are subject to the qualifications identified herein and meeting requirements laid out in the Bylaws for non-NERC-member participation in the MRC.

Selection

The CCC will conduct open nominations processes to receive nominations to fill any membership vacancies. Prospective members of the committee may be identified to the CCC via any means the committee finds acceptable, including solicited or unsolicited nomination by a recognized industry group or association, general open solicitation by the committee for nomination(s), individuals' self-nomination, directed solicitation by the committee to an individual or individuals, or referral by the Board or other NERC body or committee.

Nominating Subcommittee

The CCC will annually appoint a Nominating Subcommittee to identify, qualify, and recommend individuals to fill sector representative vacancies on the committee or, when required, to serve as the chair or vice chair of the committee. The subcommittee will identify the individuals they are recommending to the full CCC for review. Individuals recommended by the subcommittee for appointment to the committee must be approved by the Board.

Interim Approval

Upon approval of the committee, individuals identified and selected by the Nominating Subcommittee for membership on the committee may serve as members on an interim basis pending their appointment by the Board.

Expertise

When selecting individuals to recommend for committee membership, the Nominating Subcommittee will seek to engage individuals who, in aggregate, provide the committee with a level and breadth of expertise sufficient to achieve its goals and fulfill its scope and responsibilities while respecting other important factors such as industry sector, Region, interconnection, and country.

Regional Entity Members

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate an individual to serve as a member representing their organization. The Nominating Subcommittee will defer to these nominations. The nomination is non-binding upon the Board. Vacancies on the committee will exist where the Regional Reliability Organization or Regional Entity has not provided a nomination.

Canadian Members

The Nominating Subcommittee will endeavor to attract and engage Canadians with suitable qualifications and expertise in adequate numbers to satisfy Article VIII Section 4 of the Bylaws. Recognized Canadian organizations

such as the Canadian Electricity Association and Canada's Energy and Utility Regulators will be consulted and solicited for assistance in recruiting Canadians to serve on the committee. All members considered to be serving as Canadians on the committee will be expected to have an endorsement, as appropriate, of such an organization. Canadian representatives should be capable of representing Canadian viewpoints in committee activities, in addition to the sector that they otherwise represent. Consistent with practice regarding the MRC, the Board may appoint additional Canadian individuals to the committee towards satisfying Article VIII Section 4 of the Bylaws.

Industry Sector Members

The Nominating Subcommittee will assess the qualifications of nominees and select individuals to recommend to the NERC Board for appointment to the committee. The subcommittee may give preference to candidates nominated by organizations generally considered by the industry as representative of a broad cross-section of the industry sector in question, such as an industry trade association. A NERC Member sector may elect to identify sector representatives for nomination to the Nominating Subcommittee through a process approved by the NERC Board.

General Nominations and Appointment Process

The committee's secretary administers the general nominations process.

Requesting Nominations

The NERC staff will request nominations and will forward all nominations received to the Nominating Subcommittee. The Nominating Subcommittee will then prepare its recommended slate of members. The recommended slate will be reviewed by the whole committee for information purposes before it is submitted to the Board. The committee may approve the slate to serve as members on an interim basis, pending appointment by the Board at the Board's earliest convenience, but will not otherwise act on the slate.

Board Approval

The Nominating Subcommittee will present the recommended committee membership slate to the Board for approval. If the Board approves the recommended committee slate, each member on the slate is appointed. The Board may also appoint members individually as needed to meet membership balance and fill vacancies.

Vacancies and Non-participation

The committee's secretary will administer the nominations process for vacancies on the committee.

Addressed on an Ongoing Basis

Vacancies on the committee can be addressed on an ongoing basis through receipt and consideration of both solicited and unsolicited nominations for the vacant positions.

Role of the Nominating Subcommittee

Nominations received for vacancies will be vetted by the Nominating Subcommittee in the same manner as general nominations. The subcommittee may subsequently and individually recommend nominees they deem qualified to the NERC Board for consideration for appointment to the committee. Existing committee members may also approve such individuals to serve as members on an interim basis pending full appointment by the Board.

Resignations

By the Member

In the event a member can no longer serve on the committee, that member will submit a written resignation to the committee chair or the secretary.

Requested by the Chair

The chair may request any committee member who ceases to participate in the committee, as indicated by not attending or sending a proxy for two consecutive meetings, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within 30 days of the chair's request, the lack of response will be considered a resignation.

Referral to the Nominating Subcommittee

The committee chair will refer the vacancy resulting from a resignation to the Nominating Subcommittee of the committee. If a recent list of nominations is available to the Nominating Subcommittee that it deems to be valid, the subcommittee will recommend a replacement nominee; otherwise, the subcommittee will request NERC staff prepare a new solicitation for nominations to fill that position. The Nominating Subcommittee will follow the previously stated criteria in recommending a replacement.

By the Board

Committee members serve at the pleasure of the Board who may request resignation from, remove, or replace a member from the committee, as the Board deems appropriate.

Interim Approval

The committee chair may seek a vote of the committee to allow the proposed replacement member to be seated, pending appointment of the replacement at the Board's next scheduled meeting.

Proxies

A substitute representative, or proxy, may attend and vote during all or a portion of a committee meeting in lieu of a voting member provided the absent member notifies the committee chair, vice chair, or secretary of the proxy.

Notification

Such notification will be in writing (electronic medium is acceptable). The proxy representatives and their affiliation will be named in the correspondence.

Serving as Proxy

A voting member of a committee may not serve as a proxy for another voting member on the same committee (i.e. a member may not cast more than their own vote).

Exclusions

Regional Entity Staff

Regional Entity staff members who administer any portion of the Compliance and Enforcement program, Registration program, or Certification program for that Regional Entity, or for any other Regional Entity, may not serve as a member of the CCC.

Organizations

No two individuals from the same organization, or affiliated organizations, may serve concurrently on the committee. Any committee member who has a membership conflict of this nature is obligated to notify the committee secretary, who shall inform the committee chair. Members impacted by such a conflict, such as through a merger of organizations, may confer between themselves to determine which member should resign from the committee and notify the committee secretary and chair; however, if both members are within the same industry sector and cannot reach an amicable solution by determining the member to remain, the Nominating Subcommittee will review the qualifications of each member and propose the member to remain to the full committee who will determine which member shall continue to serve, subject to Board approval. If the conflict is not resolved in a timely manner by the impacted members, the committee chair shall notify all members of the

affected industry sectors recommending actions to resolve the conflict. If the membership conflict is still unresolved, the committee chair shall take the conflict to the NERC Board for resolution.

NERC Staff

The Director of Compliance Assurance shall not be a member of the committee or vote on committee business. The Director of Compliance Assurance and the secretary shall be recused from participating in any committee activity that involves monitoring of NERC's adherence to ROP or activity that the Director of Compliance Assurance oversees. If the NERC staff coordinator has been recused from participating in a Committee activity, the chair shall appoint another member of the committee as acting secretary for any meetings or other activities from which the NERC staff coordinator is recused.

Changes in Member Affiliation

A committee member whose affiliation has changed may retain the membership position under these circumstances:

1. The new organization is in the same industry sector, and
2. The member meets all other membership requirements.

Conflict of Interest

No committee member may have a conflict of interest that would impair his or her ability to fulfill obligations under this charter. Any committee member who knows of any form of membership conflict, such as working for an entity affiliated with that of another committee member, will notify the committee chair within 10 business days of obtaining that knowledge.

Meetings

In the absence of specific provisions in this manual, all committee meetings will follow Roberts Rules of Order.

Quorum

Two-thirds Requirement

The quorum necessary for transacting business at meetings of the committee is two-thirds of the voting members currently on the committee's roster.

Interim Basis

Voting members approved by the committee on an interim basis, pending appointment by the Board, will be counted in the determination of a quorum.

Lack of Quorum

If a quorum is not present at the beginning of the meeting, the committee may not take any actions requiring a vote by the committee; however, the chair may, with the consent of the members present, elect to allow discussion of the agenda items.

Voting

Actions by members of the committee will be approved upon receipt of the affirmative vote of two-thirds of the votes present (including proportional votes by Regional Representatives) at any meeting at which a quorum is present.

Antitrust Guidelines

All persons attending or otherwise participating in a NERC committee meeting will act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting.

Open Meetings

NERC committee meetings will be open to the public, except as noted below under Confidential Information.

Confidential Sessions

At the discretion of the CCC chair, a meeting or portion of a meeting may have attendance limited based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive information or confidential information to one or more parties. All hearings of compliance matters will be confidential sessions. Confidential information will only be disclosed as provided by NERC ROP 1500. Confidentiality agreements may also be applied, as necessary, to protect sensitive information or confidential information.

Types of Meetings

Meetings may be conducted in person, by conference call, or by other means. The procedures contained in this manual will apply to all meetings regardless of how they are conducted.

Majority and Minority Views

All members of a committee will be given the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, will reflect the majority as well as any minority views of the committee members. The chair will communicate both the majority and any minority views in presenting results to the Board.

Action Without a Meeting

Two-thirds Majority

Any action required or permitted at a meeting of the committee may be taken without a meeting if two-thirds of the total votes available to the members of the CCC (including the proportional votes available to Regional Representatives) approve taking the action outside of a meeting.

Procedure

Such action without a meeting will be performed by mail or electronic ballot (e.g., telephone, fax, email, or Internet) and will be recorded in the minutes as a roll call ballot. The secretary will announce the action required at least 10 days before the date on which the action is to be voted. As time permits, members should be allowed a window of 10 business days to vote. The secretary will provide the results of such an action within 10 business days of the close of the voting period.

Officers and Staff

General

Number of Positions

The committee will have two officers and one secretary.

Officers

The committee officers will be one chair and one vice chair.

Executive

The committee shall retain an Executive Committee consisting of the committee officers, subcommittee chairs, secretary, and the Director of Compliance Assurance.

Secretary

The NERC staff coordinator will serve as the committee's secretary.

Voting of Officers

The committee chair and vice chair are voting members of the committee.

Officers Nominated by the Nominating Subcommittee

The CCC Nominating Subcommittee will recommend a chair and a vice chair who are then appointed by the NERC Board for a two-year term. The term of the chair and the vice chair, except for the first year, will begin on July 1 and end on June 30.

Officers as Sector Representatives

The chair and vice chair are selected from the membership of the committee and, in addition to their chair or vice chair responsibilities, will continue to serve as a member for the sector for which they were appointed to the committee.

Chair

The chair will direct and provide general supervision of committee activities, including the following:

1. Coordinate the schedule of all committee meetings, including approval of meeting duration and location;
2. Develop committee agendas and rule on any deviation, addition, or deletion from a published agenda;
3. Preside at and manage committee meetings, including the nature and length of discussion, recognition of speakers and proxies, motions, and voting;
4. Will lead or direct the conduct of any hearings and the preparation of any adjudicatory documents by the committee under Section 408 of the NERC ROP;
5. Will ensure actions and undertakings by the committee under the NERC ROP Section 408 meet all applicable legal and due process requirements;
6. Will act as spokesperson for the committee at forums inside and outside of NERC; and
7. May attend meetings of the NERC Board when necessary to report to the Board on committee activities.

Vice Chair

The vice chair will assume the responsibilities of the chair under the following conditions:

1. At the discretion of the chair (for brief periods of time);

2. When the chair is absent or temporarily unable to perform the chair's duties; or
3. When the chair is permanently unavailable or unable to perform the chair's duties. In the case of a permanent change, the vice chair will continue to serve until a new chair is nominated and selected by the Board.

Staff Coordinator

A member of the NERC staff will be selected by NERC's Director of Compliance Assurance to serve as the staff coordinator and secretary of the committee. The staff coordinator is not a committee member and does not have a vote. Under the direction of the committee executive and applicable NERC bylaws, guidelines, and ROP, the staff coordinator will do the following:

1. Manage the day-to-day operation and business of the committee;
2. Prepare and distribute the notices of the committee meetings, prepare the meeting agenda, and prepare and distribute the minutes of the committee meetings; and
3. Act as the committee's parliamentarian.

Nominating Subcommittee

Appointment

The CCC will annually appoint a Nominating Subcommittee.

Five Members

The subcommittee will consist of five members nominated by the committee chair and approved by the committee. The chair of the subcommittee will be selected by the CCC chair from among the five subcommittee members.

Appointed Annually

The chair will appoint the subcommittee members at the first regular meeting of the committee of the calendar year.

Length of term

The subcommittee members will serve for up to 14 months or until a new Nominating Subcommittee is authorized, whichever is earlier.

Duties

In addition to the duties, rights, and privileges described elsewhere in this manual, members of the Nominating Subcommittee will:

1. Prepare a slate of committee officer candidates for submission to the NERC Board for approval, and
2. Prepare a slate of recommended individuals to fill designated committee vacancies as required.

Subordinate Groups

Committee Organization

The CCC organizational structure will be arranged as allowed in the NERC Bylaws to support a superior-subordinate hierarchy that is ordered as follows: a committee, a subcommittee, a working group, and a task force, with a committee being primary and a task force being quaternary.

Subgroups

The committee may establish subcommittees, working groups, and task forces as necessary. The committee chair may also form any of these subordinate groups on behalf of the committee. The committee will be the responsible sponsor of all subordinate subcommittees, working groups, or task forces it may create, or that its subordinate subcommittees and working groups may create. The committee will keep the Board informed of all groups subordinate to the committee.

Subcommittees

The committee may establish subcommittees to which the committee may delegate some of the committee's broadly defined continuing functions. The committee will approve the scope of each subcommittee it forms. The committee chair will appoint the subcommittee officers (typically a chair and a vice chair) for a specific term (generally two years). The subcommittee officers may be reappointed for up to two additional terms. The subcommittee will work within its assigned scope and be accountable for the responsibilities assigned to it by the committee. The formation of a subcommittee, due to the permanency of the subcommittee, will be approved by the Board.

Working Groups

The committee or any of its subcommittees may delegate specific continuing functions to a working group. The sponsoring committee or subcommittee will approve the scope of each working group it forms. The chair of the sponsoring committee or subcommittee will appoint the working group officers (typically a chair and a vice chair) for a specific term (generally two years). The working group officers may be reappointed for up to two additional terms. The sponsoring committee or subcommittee will conduct a "sunset" review of each working group every two years. The working group will be accountable for the responsibilities assigned to it by the committee or subcommittee and will, at all times, work within its assigned scope.

Task Forces

The committee, subcommittee, or working group may assign specific work of a finite duration to a task force. The sponsoring committee, subcommittee, or working group will approve the scope of each task force it forms. The chair of the sponsoring committee, subcommittee, or working group will appoint the task force officers (typically a chair and a vice chair). Each task force will have a finite duration, normally less than one year. The sponsoring group will review the task force scope at the end of the expected duration and at each subsequent meeting of the sponsoring group after that until the task force is retired. Action of the task force sponsoring group is required to continue the task force past its defined duration. The sponsoring group should consider promoting to a working group any task force that is required to work longer than one year.

Membership and Representation

The membership of each subcommittee, working group, and task force should be established to address the need for expertise and balance of interests. Each group's membership requirements will be defined within the group's approved scope.

As a general guide, the broader the group's scope, the more emphasis there should be on balancing of interests. Therefore, subcommittees would be expected to have the broadest representation of appropriate industry

sectors, while a task force may be more focused on simply having the necessary expertise, and a working group may be somewhere between.

Each member of a subordinate group, and its officers, will be appointed by the chair of the sponsoring committee or group.

To the extent subgroup membership is of a representative nature, recommendations for staffing of the group should be provided in a manner consistent with the principles outlined in the staffing of a committee, including the use of an open nominations process. Regional Entity representatives should be recommended by the Regional Entity and Canadian representatives by the Canadian Electricity Association.

Preference may also be given to representatives recommended by broadly-based industry associations.

To the extent that subgroup membership is based on providing requisite expertise, the chair of the sponsoring committee or group may appoint members based on the relevant technical qualifications.

Procedures

Subcommittees, working groups, and taskforces will conduct business in a manner consistent with all applicable sections of this manual and Robert's Rules of Order.

Hearings

General

The CCC will conduct hearings, as necessary, to fulfill its function of serving as the hearing body for any contest between NERC and a Regional Entity regarding NERC findings, penalties, or sanctions for violation(s) of Reliability Standard(s) by the Regional Entity as described in Section 408 of the NERC ROP.

Hearing Procedure

Unless specifically identified otherwise elsewhere in this charter, the CCC's hearing procedure shall follow the hearing procedure mandated and approved by jurisdictional authorities for use by NERC and the Regional Entities in the Compliance and Enforcement program.

Hearing Panel

The committee shall not have a standing hearing panel. When a hearing is to be conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the panel shall be selected by vote of a valid quorum of the committee. Voting members of the committee with little or no affiliation with parties to the hearing may be nominated or volunteer to stand for selection to the hearing panel. One or more alternates may also be selected, as the committee deems appropriate for the circumstances. A member may serve on more than one panel concurrently. A panel is disbanded upon conclusion of the hearing proceedings for which it was formed.

Attachment A

CCC Membership Structure

Primary Sector	Sub-Sector	Number of Members	Full Voting	Proportional Voting	Non-Voting
Investor-Owned Utility		2	X		
State/Municipal Utility		2	X		
Cooperative Utility		2	X		
Federal or Provincial Utility/Federal Power Marketing Administration		2	X		
Transmission Dependent Utility		2	X		
Merchant Electricity Generator		2	X		
Electricity Marketer		2	X		
Large End-use Electricity Customer		2	X		
Small End-use Electricity Customer		2	X		
Independent System Operator/Regional Transmission Organization		2	X		
Regional Entity	FRCC	1		X	
	RFC	1		X	
	ERCOT	1		X	
	MRO	1		X	
	NPCC	1		X	
	SERC	1		X	
	SPP	1		X	
	WECC	1		X	
Government	U.S. State	2	X		
	U.S. Federal	2			X
	Canadian Provincial	1			X
	Canadian Federal	1			X
Total		**34**			

Attachment 2

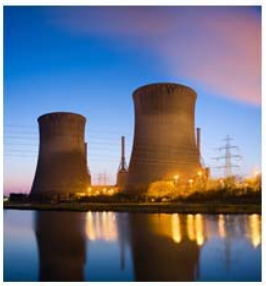
Redlined version of the proposed amendments to the CCC Charter

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance and Certification Committee Charter

[Date]

RELIABILITY | ACCOUNTABILITY



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Mission

In the capacity of a ~~NERC~~ North American Electric Reliability Corporation (NERC) Board of Trustees (Board)-appointed stakeholder committee serving and reporting directly to the NERC Board, the Compliance and Certification Committee (CCC) will engage with, support, and advise the NERC Board and NERC ~~Compliance~~ regarding all facets of the NERC Compliance Monitoring and Enforcement Program (Compliance and Enforcement program), Organization Registration program (Registration program), and Organization Certification program (Certification program). As a committee providing support and advice but otherwise independent of the execution of these programs, the CCC will monitor NERC's ~~compliance~~adherence ~~with~~ to the Rules of Procedure (ROP) for these programs ~~on an periodic ongoing basis~~. Also and in a similar manner, as a committee independent of the Reliability Standards development process, the CCC will be the body responsible for monitoring NERC's ~~compliance~~adherence ~~with~~ to the ~~Rules of Procedure~~(ROP) regarding the Reliability Standards development process~~,~~ with the exception of appeals of substantive or procedural action or inaction associated with a ~~r~~Reliability ~~s~~Standard or the ~~s~~Standards process as defined in the appeals section of the ~~Reliability Standards Development Procedure~~Standard Processes Manual. The CCC is also responsible for establishing and implementing a program to monitor NERC's compliance with the Reliability Standards that apply to NERC.

Compliance and Certification Committee Functions

To fulfill its mission, the ~~Compliance and Certification Committee~~CCC performs the following ~~–~~functions:

1. Organizes and conducts committee meetings directly with NERC ~~Compliance program~~ staff regarding all facets of the Compliance and Enforcement, Registration, and Certification programs~~;~~.[1]

~~1.~~2. ~~1~~Provides comments and recommendations to the NERC Board and NERC ~~compliance~~ staff~~;~~.

~~2.~~3. Provides comments to NERC with respect to stakeholders' perception of the policies, ~~practices~~practices, and effectiveness of the Compliance and Enforcement program, Registration program, and Certification program~~;~~.

~~3.~~4. Recommends revisions of the ~~ERO~~ ~~E~~electric ~~R~~reliability o~~O~~rganization (ERO) ~~Rules of Procedure~~ROP related to the Compliance and Enforcement program, Registration program, and Certification program to the NERC Board~~;~~.

~~4.~~5. Establishes and implements programs to monitor~~2~~:[2]

a. ~~NERC's compliance with the reliability standards that apply to~~ NERC's adherence to Section 405 for Compliance Monitoring and Enforcement, including but not limited to the uniform CMEP (Appendix 4C) and the Sanction Guidelines (Appendix 4B).~~The Compliance program's adherence to NERC's Rules of Procedure as specified in Section 405 of NERC's Rules of Procedure~~;~~.~~

~~a.~~b. NERC's adherence to Section 506 for Organization Registration and Certification, including but not limited to the Organization Registration and Certification Manual (Appendix 5A).

c. NERC's adherence ~~with the~~to Section 300 of the ~~Rules of Procedure~~ROP regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Reliability Standards process as defined in the appeals section of the Reliability Standards Development Procedure. Committee members who have participated in the development process for a particular Reliability Standard shall not participate in the c~~C~~committee's monitoring of that process.

~~b.~~d. NERC's compliance with the Reliability Standards that apply to NERC.

~~5.~~6. ~~Hearing body.~~ Serves as the hearing body for any contest regarding findings of or penalties or sanctions for violation(s) of ~~r~~Reliability ~~s~~Standard(s) where NERC is directly monitoring the entity for compliance with those ~~s~~Standards (~~R~~registered ~~E~~entity by agreement with a~~n~~ Regional Entity or absent a delegation agreement; the Region itself where approved ~~s~~Standards are applicable to the ~~R~~region) as described in ~~the NERC Rules of Procedure (ROP)~~ Section 409 of the NERC ~~Rules of Procedure~~ROP~~;~~.

~~6.~~7. ~~Mediator.~~ As directed by the NERC Board, serves as the mediator for any disagreements between NERC and the Regional Entities concerning NERC performance audits of Regional Entities' compliance programs. When directed by the Board to serve as mediator, the committee chair will appoint three disinterested members of the committee to meet with representatives of NERC and the Regional Entity to attempt to resolve the matter.

[1] Meetings are conducted ~~pursuant to~~under Section 4 of this Charter.

[2] Monitoring by the CCC is ongoing and does not preclude, interfere with or replace, in whole or in part, the NERC Board's responsibility to conduct and provide such reviews of these programs as required by Federal Energy Regulatory Commission (the Commission) ~~Order 672~~regulations, 18 C.F.R. ~~at~~ § 39.3.c: "The Electric Reliability Organization shall submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter."

7.8. Compliance administration. Actively supports the Standards Committee in the development of new and revised ssStandards by providing a pool of qualified compliance oriented personnel for participation in the compliance administration element phase of the ssStandards development process;.

8.9. Organization registration and certification. Provides assistance to NERC and the Regional Entities to implement the Compliance and Enforcement, and Organization Registration, and Certification programs; and.

9.10. Board assignments. Undertakes assignments from the Board or the Board's Compliance Committee related to compliance and enforcement, organization registration, and organization certification, and ssStandards development.

Membership

Goals

The ~~Compliance and Certification Committee~~ CCC provides for balanced discussion, ~~commentary~~commentary, and recommendations on compliance issues by bringing together a wide diversity of opinions and perspectives from NERC member sector experts who have particular familiarity, ~~knowledge~~knowledge, and experience in the area of compliance and NERC Standards and Regional S~~s~~tandards.

Appointment and Terms of Service

Members are appointed to the committee by the NERC Board and serve on the committee at the pleasure of the Board. Member terms are the lesser ~~of:~~of three years from appointment or interim approval (Section 5.b)~~,~~, replacement, or removal by the Board. Members may be reappointed at the conclusion of a term. There is no limitation on the number of times a member may be reappointed. A member may be recommended to the Board for reappointment by the Nominating Subcommittee by self- nomination. To the extent practicable, member terms will be staggered such that approximately one-~~-~~third of the committee is subject to reappointment or replacement each year.

Qualifications

Individuals deemed qualified to serve on the committee will generally include senior-~~-~~level industry experts who have particular familiarity, knowledge, and experience in the area of compliance, compliance enforcement, compliance administration and management, organization responsibilities and registration, organization certification, and NERC Standards and Regional S~~s~~tandards. These individuals should be involved with internal compliance programs within their respective organizations.

Expectations

Committee members are expected to represent the interests of the sector they represent~~,~~ to the best of their ability and judgment. In addition to the duties, rights, and privileges described elsewhere in this charter, committee members will ~~do the following:~~:

1. Act consistently during meetings with the procedures in this manual and Robert's Rules of Order;~~,~~
2. Demonstrate and provide knowledge and expertise in support of committee activities;~~,~~
3. Adjudicate in a fair and unbiased manner that meets applicable legal and due process requirements when participating in hearing procedures conducted under ~~pursuant to~~ the NERC ~~Rules of Procedure~~ROP ~~(ROP)~~ Section 409;~~,~~
4. Solicit comments and opinions from constituents and groups of constituents or trade organizations represented by the member and convey them to the committee;~~,~~
5. Respond promptly to all committee requests, including requests for reviews, comments, and votes on issues before the committee;~~,~~
6. Arrange for a proxy to attend and vote at committee meetings in the member's absence; and~~,~~
7. Respond promptly to all requests to register for committee meetings.

Representation

The membership structure of the ~~Compliance and Certification Committee (~~CCC~~)~~ will be modeled upon the membership structure of the NERC Member Representatives Committee (MRC) as described in NERC's Bylaws (the Bylaws) Article VIII Section 2 [see Attachment A]. This ~~will~~ should produce a committee that has an

appropriate balance of entities subject to compliance with the NERC Reliability Standards and NERC's Compliance and Enforcement program, and others affected by the ~~s~~Standards and the Compliance and Enforcement program.

Regional Entities

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate one member to the committee. In ~~aggregate~~aggregate, the sector will have voting strength equivalent to two members. The voting weight of each ~~r~~Regional member's vote will be set such that the sum of the weight of all available ~~r~~Regional members' votes is two votes.

Canadian Representation

The committee structure will include representation by Canadians as laid out in Article VIII Section 4 of the Bylaws.

NERC Membership

Users, ~~owners~~owners, and operators of the bulk power system are subject to the Compliance, ~~Registration~~Registration, and Certification programs ~~irrespective~~ regardless of whether they are NERC members. It is expected that committee members will generally be from organizations who are NERC members; h~~. H~~owever, committee members may be non-members of NERC who are subject to the qualifications identified herein and meeting requirements laid out in the Bylaws for non-NERC-member participation in the MRC.

Selection

The CCC will conduct open nominations processes to receive nominations to fill any membership vacancies. Prospective members of the committee may be identified to the CCC via any means the committee finds acceptable, including~~:~~ solicited or unsolicited nomination by a recognized industry group or association,~~;~~ general open solicitation by the committee for nomination(s),~~;~~ individuals' self-nomination,~~;~~ directed solicitation by the committee to an individual or individuals, or~~;~~ referral by the Board or other NERC body or committee.

Nominating Subcommittee

The CCC will annually appoint ~~create~~ a Nominating Subcommittee ~~yearly~~ to identify, qualify, and recommend individuals to fill sector representative vacancies on the committee or, when required, to serve as the chair or vice chair of the committee. The subcommittee will identify the individuals they are recommending to the full CCC for review. Individuals recommended by the subcommittee for appointment to the committee must be approved by the Board.

Interim Approval

Upon approval of the ~~committee~~committee, individuals identified and selected by the Nominating Subcommittee for membership on the committee may serve as members on an interim basis~~,~~ pending their appointment by the Board.

Expertise

When selecting individuals to recommend for committee membership, the Nominating Subcommittee will seek to engage individuals who, in aggregate, provide the committee with a level and breadth of expertise sufficient to achieve its goals and fulfill its scope and responsibilities~~,~~ while respecting other important factors such as industry sector, R~~r~~egion, i~~I~~nterconnection, and country.

Regional Entity Members

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate an individual to serve as a member representing their organization. The Nominating Subcommittee will defer to these nominations. The nomination is non-binding upon the Board. Vacancies on the committee will exist where the R~~r~~egional R~~r~~eliability O~~o~~rganization or R~~r~~egional E~~e~~ntity has not provided a nomination.

Canadian Members

The Nominating Subcommittee will endeavor to attract and engage Canadians with suitable qualifications and expertise in adequate numbers to satisfy Article VIII Section 4 of the Bylaws. Recognized Canadian organizations such as the Canadian Electricity Association and Canada's Energy and Utility Regulators ~~(CAMPUT)~~~~CAMPUT~~ will be consulted and solicited for assistance in recruiting Canadians to serve on the committee. A ~~and a~~ll members considered to be serving as Canadians on the committee will be expected to have an endorsement, as appropriate, of such an organization. Canadian representatives should be capable of representing Canadian viewpoints in committee activities, in addition to the ~~sector which~~sector that they otherwise represent. Consistent with practice regarding the MRC, the Board may appoint additional Canadian individuals to the committee towards satisfying Article VIII Section 4 of the Bylaws.

Industry Sector Members

The Nominating Subcommittee will assess the qualifications of nominees and select individuals to recommend to the NERC Board for appointment to the committee. The subcommittee may give preference to candidates nominated by organizations generally considered by the industry as representative of a broad cross-section of the industry sector in question, such as an industry trade association. A NERC Member sector may elect to identify sector representatives for nomination to the Nominating Subcommittee through a process approved by the NERC Board.

General Nominations and Appointment Process

The committee's secretary administers the general nominations process.

Requesting Nominations

The NERC staff will request nominations ~~NERC staff will~~and will forward ~~received~~all nominations received ~~received~~ to the Nominating~~ions~~ Subcommittee. The Nominating Subcommittee will then prepare its recommended slate of members. The recommended slate will be reviewed by the whole committee for information purposes before it is submitted to the Board. The committee may approve the slate to serve as members on an interim basis, pending appointment by the Board at the Board's earliest convenience, but will not otherwise act on the slate.

Board Approval

The Nominating Subcommittee will present the recommended committee membership slate to the Board for approval. If the Board approves the recommended committee ~~slate~~slate, each member on the slate is appointed. The Board may also appoint members individually as needed to meet membership balance and fill vacancies.

Vacancies and Non-participation

The committee's secretary will administer the nominations process for vacancies on the committee.

Addressed on an Ongoing Basis

Vacancies on the committee can be addressed on an ongoing basis through receipt and consideration of both solicited and unsolicited nominations for the vacant positions.

Role of the Nominating Subcommittee

Nominations received for vacancies will be vetted by the Nominating Subcommittee in the same manner ~~as nominations received~~ as general nominations. The subcommittee may subsequently and individually recommend nominees they deem qualified to the NERC Board for consideration for appointment to the committee. E~~;e~~xisting committee members may also approve such individuals to serve as members on an interim basis pending full appointment by the Board.

Resignations

By the Member

In the event a member can no longer serve on the committee, that member will submit a written resignation to the committee chair or the secretary.

Requested by the Chair

The chair may request any committee member who ceases to participate in the committee, as indicated by not attending or sending a proxy for two consecutive meetings, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within 30 days of the chair's request, the lack of response will be considered a resignation.

Referral to the Nominating Subcommittee

The committee chair will refer the vacancy resulting from a resignation to the Nominating Subcommittee of the committee. If a recent list of nominations is available to the Nominating Subcommittee that it deems to be valid, the subcommittee will recommend a replacement nominee; otherwise, the subcommittee will request NERC staff prepare a new solicitation for nominations to fill that position. The Nominating Subcommittee will follow the previously stated criteria in recommending a replacement.

By the Board

Committee members serve at the pleasure of the Board who may request resignation from, ~~remove~~remove, or replace a member from the ~~committee~~committee, as the Board deems appropriate.

Interim Approval

The committee chair may seek a vote of the committee to allow the proposed replacement member to be seated, pending appointment of the replacement~~,~~ at the Board's next scheduled meeting.

Proxies

A substitute representative, or proxy, may attend and vote during all or a portion of~~,~~ a committee meeting in lieu of a voting member~~,~~ provided the absent member notifies the committee chair, vice chair, or secretary of the proxy.

Notification

Such notification will be in writing (electronic medium is acceptable). The proxy representatives and their affiliation will be named in the correspondence.

~~May not serve as a proxy for another member~~Serving as Proxy

A voting member of a committee may not serve as a proxy for another voting member on the same committee (i.e. a member may not cast more than their own vote).

Exclusions

Regional Entity S~~s~~taff

Regional Entity staff members who administer any portion of the Compliance and Enforcement program, Registration program, or Certification program~~, or Readiness Evaluation program~~ for that Regional Entity, or for any other Regional Entity, may not serve as a member of the CCC.

Organizations

No two individuals from the same organization, or affiliated organizations, may serve concurrently on the committee. Any committee member who has a membership conflict of this nature is obligated to notify the committee secretary, who shall inform the committee chair. Members impacted by such a conflict, such as

through a merger of organizations, may confer between themselves to determine which member should resign from the committee and notify the committee secretary and chair; h. However, if both members are within the same industry sector and cannot reach an amicable solution by determining the member to remain, the Nominating Subcommittee will review the qualifications of each member and propose the member to remain to the full committee who will determine which member shall continue to serve, subject to Board approval. If the conflict is not resolved in a timely manner by the impacted members, the committee chair shall notify all members of the affected industry sectors recommending actions to resolve the conflict. If the membership conflict is still unresolved, the committee chair shall take the conflict to the NERC Board for resolution.

NERC Staff

The Director of Compliance Operations Assurance shall not be a member of the committee or vote on committee business. The Director of Compliance Operations Assurance and the Ssecretary shall be recused from participating in any committee activity that involves monitoring of NERC's compliance withadherence to Rules of ProcedureROP or activity that the Director of Compliance Operations Assurance oversees. If the NERC staff coordinator has been recused from participating in a Committee activity, the chair shall appoint another member of the committee as acting secretary for any meetings or other activities from which the NERC staff coordinator is recused.

Changes in Member Affiliation

A committee member whose affiliation has changed may retain the membership position under these circumstancesif:

1. The new organization is in the same industry sector, and
2. The member meets all other membership requirements.

Conflict of Interest

No committee member may have a conflict of interest that would impair his or her ability to fulfill obligations under this charter. Any committee member who knows of any form of membership conflict, such as working for an entity affiliated with that of another committee member, will notify the committee chair within ten 10 business days of obtaining that knowledge.

Meetings

In the absence of specific provisions in this manual, all committee meetings will follow Roberts Rules of Order, ~~Newly Revised.~~

Quorum

~~Two-thirds of the voting members~~Two-thirds Requirement

The quorum necessary for transacting business at meetings of the committee is two-thirds of the voting members currently on the committee's roster.

~~Includes members approved on interim basis~~Interim Basis

Voting members approved by the committee on an interim basis, pending appointment by the Board, will be counted in the determination of a quorum.

Lack of Q~~a q~~uorum

If a quorum is not present at the beginning of the meeting, the committee may not take any actions requiring a vote by the committee; h~~. H~~owever, the chair may, with the consent of the members present, elect to allow discussion of the agenda items.

Voting ~~— actions require two-thirds majority~~

Actions by members of the c~~C~~ommittee will be approved upon receipt of the affirmative vote of two-thirds of the votes present (including proportional votes by Regional Representatives) at any meeting at which a quorum is present~~. .~~ ~~The chairmanchair and vice chair may vote.~~

Antitrust Guidelines

All persons attending or otherwise participating in a NERC committee meeting will act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting.

Open Meetings

NERC committee meetings will be open to the public, except as noted below under Confidential Information.

Confidential Sessions

At the discretion of the CCC c~~C~~hair, a meeting or portion of a meeting ~~of a committee~~ may have attendance limited based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive information or confidential information to one or more parties. All hearings of compliance matters will be confidential sessions. Confidential information will only be disclosed as provided by NERC ~~Rule of Procedure~~ROP 1500. Confidentiality agreements may also be applied, as necessary, to protect sensitive information or confidential information.

Types of Meetings

Meetings may be conducted in person, by conference call, or by other means. The procedures contained in this manual will apply to all meetings regardless of how they are conducted.

Majority and M~~m~~inority V~~v~~iews

All members of a committee will be givenafforded the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, will reflect the majority as well as any minority views of the committee members. The chair will communicate both the majority and any minority views in presenting results to the Board.

Action W~~w~~ithout a Meeting

~~Requires~~ T~~t~~wo-thirds M~~m~~ajority

Any action required or permitted at a meeting of the committee may be taken without a meeting if two-thirds of the total votes available to the members of the CCC (including the proportional votes available to Regional Representatives) approve taking the action outside of a meeting.

Procedure

Such action without a meeting will be performed by mail or electronic ballot (e.g., telephone, fax~~csimile~~, e~~-~~mail, or Internet)~~,~~ and will be recorded in the minutes as a roll call ballot. The secretary will announce the action required at least 10 days before~~prior to~~ the date on which the action is to be voted. As time permits, members should be allowed a window of 10~~ten~~ business days to vote. The secretary will provide the results of such an action within 10~~ten~~ business days of the close of the voting period.

Officers and Staff

General

Number of Positions

The committee will have two officers and onea secretary.

Officers

The committee officers will be one chair and one vice chair.

Executive

The committee shall retain an Executive Committee consisting of the committee officers, subcommittee chairs, secretary, and the Director of Compliance Assurance.

Secretary

The NERC staff coordinator will serve as the committee's secretary.

Officers may voteVoting of Officers

The committee chair and vice chair are voting members of the committee.

Officers nominated Nominated by the Nominating Subcommittee

The CCC Nominating Subcommittee will recommend a chair and a vice chair who are then appointed by the NERC Board for a two-year term. The term of the chair and the vice chair, except for the first year, will begin on July 1 and end on June 30.

Officers remain as Ssector Rrepresentatives

The chair and vice chair are selected from the membership of the committee and, in addition to their chair or vice chair responsibilities, will continue to serve as a member for the sector for which they were appointed to the committee.

Chair

The chair will direct and provide general supervision of committee activities, including the following:

1. Coordinate the schedule of all committee meetings, including approval of meeting duration and location;
2. Develop committee agendas and rule on any deviation, addition, or deletion from a published agenda;
3. Preside at and manage committee meetings, including the nature and length of discussion, recognition of speakers and proxies, motions, and voting;
4. Will lead or direct the conduct of any hearings and the preparation of any adjudicatory documents by the committee underpursuant to Section 409 of the NERC Rules of ProcedureROP (ROP) Section 409;
5. Will iensure actions and undertakings by the committee pursuant tounder the NERC Rules of ProcedureROP (ROP) Section 409 meet all applicable legal and due process requirements;
6. Will act as spokesperson for the committee at forums insidewithin and outside of NERC; and.
7. May attend meetings of the NERC Board when necessary to report to the Board on committee activities.

Vice Cehair

The vice chair will assume the responsibilities of the chair under the following conditions:

1. At the discretion of the chair (for brief periods of time);

2. When the chair is absent or temporarily unable to perform the chair's duties; or
3. When the chair is permanently unavailable or unable to perform the chair's duties. In the case of a permanent change, the vice chair will continue to serve until a new chair is nominated and selected by the Board.

Staff Coordinator

A member of the NERC staff will be selected by NERC's Director of Compliance ~~Operations~~ Assurance to serve as the staff coordinator and secretary of the committee. The staff coordinator is not a committee member and does not have a vote. Under the direction of the committee executive and applicable NERC bylaws, guidelines, and ~~r~~Rules of p~~P~~rocedureROP, the staff coordinator will do the following:

1. Manage the day-to-day operation and business of the committee;
2. Prepare and distribute the notices of the committee meetings, prepare the meeting agenda, and prepare and distribute the minutes of the committee meetings; and~~.~~
3. Act as the committee's parliamentarian.

Nominating Subcommittee

Appointment

The ~~Compliance and Certification Committee (~~CCC~~)~~ will annually appoint a Nominating Subcommittee.

Five M~~m~~embers

The subcommittee will consist of five members nominated by the committee chair and approved by the committee. The chair of the subcommittee will be selected by the CCC chair from among the five subcommittee members.

Appointed A~~a~~nnually

The ~~chairman~~chair will appoint the subcommittee members at the first regular meeting of the committee of the calendar year.

~~Serve for 14 months~~Length of term

The subcommittee members will serve for up to 14 months or until ~~such time~~ ~~as~~ a new Nominating Subcommittee is authorized, whichever is earlier.

Duties

In addition to the duties, rights, and privileges described elsewhere in this manual, members of the Nominating Subcommittee will ~~do the following~~:

1. Prepare a slate of committee officer candidates for submission to the NERC Board for approval, and~~.~~
2. Prepare a slate of recommended individuals to fill designated committee vacancies as required.

Subordinate Groups

Committee Oorganization ~~hierarchy~~

The ~~Compliance and Certification Committee~~ CCC organizational structure will be arranged as allowed in the NERC Bylaws to support a superior-subordinate hierarchy that is ordered as follows: a

~~1.~~ cCommittee, a ~~e~~

~~2.~~ sSubcommittee, a

~~3.~~ wWorking gGroup, and a ~~p~~

~~4.~~ tTask fForce, with a committee being primary and a task force being quaternary.

Subgroups

The committee may establish subcommittees, working groups, and task forces as necessary. The committee chair may also form any of these subordinate groups on behalf of the committee. The committee will be the responsible sponsor of all subordinate subcommittees, working groups, or task forces it may create, or that its subordinate subcommittees and working groups may create. The committee will keep the Board informed of all groups subordinate to the committee.

Subcommittees

The committee may establish subcommittees to which the committee may delegate somecertain of the committee's broadly defined continuing functions. The committee will approve the scope of each subcommittee it forms. The committee chair will appoint the subcommittee officers (typically a chair and a vice chair) for a specific term (generally two years). The subcommittee officers may be reappointed for up to two additional terms. The subcommittee will work within its assigned scope and be accountable for the responsibilities assigned to it by the committee. The formation of a subcommittee, due to the permanency of the subcommittee, will be approved by the Board.

Working Groups

The committee or any of its subcommittees may delegate specific continuing functions to a working group. The sponsoring committee or subcommittee will approve the scope of each working group it forms. The chair of the sponsoring committee or subcommittee will appoint the working group officers (typically a chair and a vice chair) for a specific term (generally two years). The working group officers may be reappointed for up to two additional terms. The sponsoring committee or subcommittee will conduct a "sunset" review of each working group every two years. The working group will be accountable for the responsibilities assigned to it by the committee or subcommittee and will, at all times, work within its assigned scope.

Task Forces

The committee, subcommittee, or working group may assign specific work of a finite duration to a task force. The sponsoring committee, subcommittee, or working group will approve the scope of each task force it forms. The chair of the sponsoring committee, subcommittee, or working group will appoint the task force officers (typically a chair and a vice chair). Each task force will have a finite duration, normally less than one year. The sponsoring group will review the task force scope at the end of the expected duration and at each subsequent meeting of the sponsoring group after that until the task force is retired. Action of the task force sponsoring group is required to continue the task force past its defined duration. The sponsoring group should consider promoting to a working group any task force that is required to work longer than one year.

~~Subgroup~~ Membership and Representation

The membership of each subcommittee, working group, and task force should be established to address the need for expertise and balance of interests. Each group's membership requirements will be defined within the group's approved scope.

As a general guide, the broader the group's scope, the more emphasis there should be on balancing of interests. Therefore, subcommittees would be expected to have the broadest representation of appropriate industry sectors, while a task force may be more focused on simply having the necessary expertise, and a working group may be somewhere between.

Each member of a subordinate group, and its officers, will be appointed by the chair of the sponsoring committee or group.

To the extent subgroup membership is of a representative nature, recommendations for staffing of the group should be provided in a manner consistent with the principles outlined in the staffing of a committee, including the use of an open nominations process. Regional Entity representatives should be recommended by the Regional Entity and Canadian representatives by the Canadian Electricity Association.

Preference may also be given to representatives recommended by broadly-based industry associations.

To the extent that subgroup membership is based on providing requisite expertise, the chair of the sponsoring committee or group may appoint members based on the relevant technical qualifications.

~~Subgroup~~ Procedures

Subcommittees, working groups, and taskforces will conduct business in a manner consistent with all applicable sections of this manual and Robert's Rules of Order.

Hearings

General

The ~~Compliance and Certification Committee~~ CCC will conduct hearings, as necessary, to fulfill its function of serving as the hearing body for any contest between NERC and a Regional Entity ~~(RE)~~ regarding NERC findings, ~~of or~~ penalties, or sanctions for violation(s) of ~~r~~Reliability ~~s~~Standard(s) by the Regional Entity as described in ~~the NERC Rules of Procedure (ROP)~~ Section 409 of the NERC ~~Rules of Procedure~~ROP.

Hearing Procedure

Unless specifically identified otherwise elsewhere in this charter, the CCC's hearing procedure shall follow the hearing procedure mandated and approved by jurisdictional authorities for use by NERC and the Regional Entities in the Compliance and Enforcement program.

Hearing Panel

The committee shall not have a standing hearing panel. When a hearing is to be ~~conducted~~conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the panel shall be selected by vote of a valid quorum of the committee. Voting members of the committee ~~at arm's length from~~with little or no affiliation with ~~-~~parties to the hearing may be nominated or volunteer to stand for selection to the hearing panel. One or more alternates may also be selected ~~if/as~~, as the committee deems appropriate for the circumstances. A member may serve on more than one panel concurrently. A panel is disbanded upon conclusion of the hearing proceedings for which it was formed.

Attachment A ~~— CCC Membership Structure~~

CCC Membership Structure

Primary Sector	Sub-Sector	Number of Members	Full Voting	Proportional Voting	Non-Voting
Investor-Owned Utility		2	X		
State/Municipal Utility		2	X		
Cooperative Utility		2	X		
Federal or Provincial Utility/Federal Power Marketing Administration		2	X		
Transmission Dependent Utility		2	X		
Merchant Electricity Generator		2	X		
Electricity Marketer		2	X		
Large End-use Electricity Customer		2	X		
Small End-use Electricity Customer		2	X		
Independent System Operator/Regional Transmission Organization		2	X		
Regional Entity	FRCC	1		X	
	RFC	1		X	
	ERCOT	1		X	
	MRO	1		X	
	NPCC	1		X	
	SERC	1		X	
	SPP	1		X	
	WECC	1		X	
Government	U.S. State	2	X		
	U.S. Federal	2			X
	Canadian Provincial	1			X
	Canadian Federal	1			X
Total		**34**			

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability	**)**	
Corporation	**)**	**Docket No. FA11-21-000**

COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The North American Electric Reliability Corporation ("NERC")[1] submits this compliance filing in accordance with the Commission's January 16, 2013 Order in Docket No. FA11-21-000.[2] In the January 16 Order, the Commission approved a Settlement Agreement between the Office of Enforcement ("Enforcement") and NERC related to Enforcement's findings and recommendations arising out of its 2012 performance audit of NERC. Specifically, Section II.7(b)(i) of the Settlement Agreement requires that:

> Within forty-five days of the end of each quarter, beginning with the quarter ending March 31, 2013, NERC will file with the Commission the unaudited report of the NERC budget-to-actual spending variances during the preceding quarter. This report will include information regarding sources and uses of operating and working capital reserves and will match or exceed the level of detail of the quarterly budget-to-actual variance report of NERC expenditures attached to the agenda of NERC Board of Trustees Finance and Audit Committee's October 2012 meeting.[3]

Attached hereto is the unaudited report of NERC's budget-to-actual variance information for the first quarter of 2015, in accordance with the January 16 Order. This variance information was

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[1] NERC was certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[2] *See North American Electric Reliability Corporation, Order Approving Settlement Agreement*, 142 FERC ¶ 61,042 (2013) ("January 16 Order").

[3] *Id.*

posted on NERC's website and reviewed in open session at the May 6, 2015 meeting of the NERC Finance and Audit Committee. The unaudited report was accepted by the NERC Board of Trustees at its meeting on May 7, 2015.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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*Persons to be included on the Commission's official service list

II. CONCLUSION

NERC respectfully requests that the Commission accept this filing as compliant with Section II.7(b)(i) of the Settlement Agreement and the Commission's January 16 Order in Docket No. FA11-21-000.

Respectfully submitted,

/s/ Meredith M. Jolivert

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Counsel for North American Electric Reliability Corporation

Dated: May 15, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 15th day of May, 2015.

/s/ Meredith M. Jolivert

Meredith M. Jolivert
Counsel for North American
Electric Reliability Corporation

ATTACHMENT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation Summary of Results as of March 31, 2015

Through March 31, 2015, NERC was $1.6M, 9.3%, under its expense and fixed asset budget, including costs related to the Cyber Risk Information Sharing Program (CRISP). As reflected in the following table, NERC is projecting to be approximately $358.0k, 0.5%, under budget at year end, due to a variety of reasons, but primarily due to lower than budgeted costs for CRISP.

YTD Actual versus YTD Budget and 2015 Projection versus 2015 Total Budget by Category

	2015 Actual	2015 Budget	2015 Variance Over(Under)	%	2015 Projection	2015 Annual Budget	2015 Projected Variance from Budget Over(Under)	%
TOTAL FUNDING	**20,395,475**	**17,700,754**	**2,694,721**	**15.2%**	**65,656,973**	**67,371,264**	**(1,714,291)**	**-2.5%**
BUDGET - EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	9,274,547	9,316,593	(42,046)	-0.5%	35,380,411	35,803,311	(422,900)	-1.2%
MEETINGS, TRAVEL and CONFERENCE CALLS	871,033	905,559	(34,526)	-3.8%	3,758,931	3,566,146	192,785	5.4%
CONSULTANTS and CONTRACTS	2,519,192	3,995,150	(1,475,958)	-36.9%	13,509,173	14,311,466	(802,293)	-5.6%
RENT	701,577	746,939	(45,362)	-6.1%	2,987,777	2,987,777	-	0.0%
OFFICE COSTS, PROFESSIONAL SERVICES and MISCELLANEOUS	1,421,594	1,557,744	(136,150)	-8.7%	6,264,196	6,231,108	33,088	0.5%
Other Non-Operating Expenses	5,972	32,750	(26,778)	-81.8%	75,000	131,000	(56,000)	-42.7%
FIXED ASSET PURCHASES (excludes the credit for depreciation)	741,987	578,083	163,903	28.4%	4,315,807	3,618,500	697,307	19.3%
TOTAL BUDGET	**15,535,903**	**17,132,818**	**(1,596,915)**	**-9.3%**	**66,291,295**	**66,649,308**	**(358,014)**	**-0.5%**
FTEs	**188.00**	**192.35**	**(4.35)**	**-2.3%**	**190.73**	**192.30**	**(1.57)**	**-0.8%**

Excluding CRISP, NERC was $107.1k, 0.7%, under budget and is projecting to be $937.0k, 1.6%, over budget at year end due to costs associated with (1) consulting support for assessment studies regarding the Environmental Protection Agency's proposed Clean Power Plan; (2) contract costs for multiple reliability tools and costs of a secure alert system that was anticipated to be replaced by another system at lower costs[1]; and (3) the use of reserves for leasehold improvements in the Atlanta and Washington, DC offices, which were approved by the Finance and Audit Committee at their meeting in November, 2014. The following table and the summary of variances by expense category reflect year-to-date (YTD) actual results and 2015 projected results without CRISP. A summary of results for CRISP is also provided on page 4. It's important to keep in mind that this projection is preliminary and subject to change. This year end projection will be utilized in preparation of the initial draft of NERC's 2016 business plan and budget, which will be posted on May 19th. It will be further refined and updated as part of the second quarter variance report and the final draft of the 2016 business plan and budget which is scheduled to be posted on July 15th.

[1] A replacement system is currently under evaluation.

YTD Actual versus YTD Budget and 2015 Projection versus 2015 Total Budget by Category (Excluding CRISP)

	2015 Actual	2015 Budget	2015 Variance Over(Under)	%	2015 Projection	2015 Annual Budget	2015 Projected Variance from Budget Over(Under)	%
TOTAL FUNDING	**15,197,487**	**15,233,058**	**(35,570)**	**-0.2%**	**57,550,142**	**57,550,142**	**-**	**0.0%**
BUDGET - EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	9,227,709	9,197,183	30,526	0.3%	35,156,055	35,344,061	(188,006)	-0.5%
MEETINGS, TRAVEL and CONFERENCE CALLS	869,134	893,053	(23,919)	-2.7%	3,708,931	3,516,146	192,785	5.5%
CONSULTANTS and CONTRACTS	1,855,108	2,078,637	(223,529)	-10.8%	7,064,561	6,645,411	419,150	6.3%
RENT	701,577	746,939	(45,362)	-6.1%	2,987,777	2,987,777	-	0.0%
OFFICE COSTS, PROFESSIONAL SERVICES and MISCELLANEOUS	1,392,316	1,393,991	(1,675)	-0.1%	5,547,871	5,576,108	(28,237)	-0.5%
Other Non-Operating Expenses	5,972	32,750	(26,778)	-81.8%	75,000	131,000	(56,000)	-42.7%
FIXED ASSET PURCHASES (excludes the credit for depreciation)	736,729	553,083	183,646	33.2%	4,115,807	3,518,500	597,307	17.0%
TOTAL BUDGET	**14,788,546**	**14,895,637**	**(107,091)**	**-0.7%**	**58,656,002**	**57,719,003**	**936,999**	**1.6%**
FTEs	**186.9**	**190.5**	**(3.6)**	**-1.9%**	**188.9**	**190.4**	**(1.6)**	**-0.8%**

Following is a brief summary of variances by major categories:

- Personnel expenses were over budget $30.5k, 0.3%, due to higher than budgeted employment agency fees and payroll taxes, offset by lower than budgeted benefits and retirement costs. Personnel expenses are projected to be $188.0k, 0.5% under budget at year end. There were 4.4, 2.3%, fewer FTEs on staff than budgeted through March 31, 2015. The 2015 budget for personnel expenses and total FTEs reflects a 6% vacancy assumption to account for attrition and timing of hiring open positions.
    - Salaries expense, which consists of salaries, incentive compensation, employment agency fees and temporary office services, was $73.4k, 1.1%, over budget through March 31st due to higher than budgeted employment agency fees.
    - Payroll taxes were over budget $73.7k, 10.4%, through March 31st, and are projected to be over budget $132.8k, 7.9%, at year end due to a higher maximum salary subject to taxes in 2015 than was budgeted. Higher than budgeted expense through March 31st was also due to timing related to payroll taxes paid in February in connection with the payout of incentive compensation.
    - Employee Benefits were $61.8k, 7.0%, under budget and are projected to be under budget $167.2k, 4.7%, at year end due to lower than budgeted renewal rates for employee health benefits.
    - Retirement costs were $127.4k, 15.4%, under budget due to having fewer FTEs on staff. Retirement costs are projected to be $196.7k, 6.6%, under budget at year end due to timing of hiring open positions which delays eligibility in the savings and investment plan.

- Meeting, travel and conferencing expenses were collectively under budget $23.9k, 2.7%, through March 31st, and are projected to be $192.8k, 5.5%, over budget at year end. Travel expenses were over budget $14.7k through March, 2015, and are projected to be $145.4k over budget at year end primarily due to increased travel related to implementation of risk-based CMEP and event analysis. Management will be reviewing projected travel and meeting expenses further in an effort to identify opportunities to reduce this projected budget variance.
- Consultant and Contract expenses were $223.5k, 10.8%, under budget, primarily due to timing of the budget versus actual payments for numerous projects throughout the organization. Consultant and contract expenses are projected to be $419.2k, 6.3%, over budget at year end. The following table summarizes existing and projected over budget variances by department.
    - RAPA - Over budget $197.6k YTD and projected to be $145.3k over budget at year end due to costs for consulting support for assessment studies regarding the Environmental Protection Agency's proposed Clean Power Plan. The use of operating reserves received all necessary corporate authorization as required by NERC's Working Capital and Operating Reserve Policy.
    - Reliability Risk Management – Over budget YTD and projected to be over budget at year end due to higher than budgeted costs for multiple reliability tools and costs resulting from delays in the replacement of a secure alert system, as previously noted.
    - ES-ISAC – Under budget YTD due to timing difference between actual expenses incurred and the budget, which is allocated equally throughout the year.
    - Training, Education and Operator Certification - Under budget YTD due to timing difference between actual expenses incurred and the budget, which is allocated equally throughout the year.
    - General and Administrative – The YTD actual and projected year end over budget variance is related to the ERO effectiveness survey which began in 2014 and carried over into 2015.
    - Information Technology, Human Resources and Finance and Accounting - Under budget YTD due to timing difference between actual expenses incurred and the budget, which is allocated equally throughout the year.

SUMMARY OF CONSULTANT AND CONTRACT EXPENSES BY DEPARTMENT

CONSULTANTS and CONTRACTS	2015 Actual	2015 Budget	Over(Under)	2015 Projection	2015 Annual Budget	Variance from Budget Over(Under)
COMPLIANCE ASSURANCE	-	97,003	(97,003)	388,000	388,000	-
RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS	685,206	487,612	197,594	1,100,780	955,450	145,330
RELIABILITY RISK MANAGEMENT	532,185	437,868	94,318	1,286,655	1,077,321	209,334
ES-ISAC	103,274	272,530	(169,257)	1,111,867	1,090,135	21,732
TRAINING, EDUCATION and OPERATOR CERTIFICATION	110,139	188,028	(77,890)	746,014	752,130	(6,116)
GENERAL and ADMINISTRATIVE	48,870	-	48,870	48,870	-	48,870
POLICY and EXTERNAL AFFAIRS	500	3,750	(3,250)	15,000	15,000	-
INFORMATION TECHNOLOGY	319,898	432,403	(112,505)	1,729,600	1,729,600	-
HUMAN RESOURCES	27,911	74,571	(46,660)	298,275	298,275	-
FINANCE and ACCOUNTING	27,126	84,872	(57,746)	339,500	339,500	-
CONTRACTS and CONSULTANTS (excluding CRISP)	**1,855,108**	**2,078,637**	**(223,529)**	**7,064,561**	**6,645,411**	**419,150**

- Other Non-Operating Expenses were $26.8k, 81.8%, under budget through March 31st, and are projected to be $56.0k, 42.7%, under budget at year end due to a lower than budgeted interest expense related to the capital financing loan. As a result of budget under runs in 2014, management did not draw on the loan in 2014 as was planned when the 2015 budget was developed.
- Fixed Asset Purchases, which excludes the credit for depreciation, were $183.6k, 33.2%, over budget through March 31st and are projected to be $597.3k, 17.0%, over budget at year end due to leasehold improvements in the Atlanta and Washington, DC offices, which were approved by the Finance and Audit Committee at their meeting in November, 2014.

CRISP was $1.5M, 65.1% under budget through March 31st, and is projected to be $1.2M, 13.2%, under budget at year end, primarily due to lower than budgeted contract and consulting expense. When the 2015 budget was prepared, it was assumed that all CRISP contracts would be executed and associated expenses would be incurred in 2015. However, as previously reported, a portion of CRISP expenses that were budgeted in 2015 were incurred in 2014. Based upon 2015 contract costs, which were finalized after the 2015 budget was submitted to FERC, contract and consulting expense related to CRISP is projected to be $1.2M under budget in 2015. This will also have the effect of reducing 2015 funding from CRISP participants, since CRISP contractual funding mechanisms match funding to actual costs. As reflected in the projected year-end balance in CRISP Reserves on page 6, we project the change in reserves from current year operations to be $14.5k. Any under runs in actual versus budgeted CRISP costs which are funded by CRISP participants will be credited to CRISP participants pursuant to the terms of the CRISP participant agreements.

OPERATING RESERVE ANALYSIS

As of March 31, 2015, the balance in working capital and operating reserves was $12.0M, which was $6.1M higher than budget. This higher than budgeted reserve balance was the result of two factors that were not anticipated at the time the 2015 budget was approved. First, the reserve balance reflects $4.3M in additional CRISP reserves due to timing differences between receipt of third-party funding for CRISP, which occurs at the beginning of the year, and expenses incurred throughout the year. Pursuant to the agreements with CRISP participants, any excess in funding over expenses is returned to participants per the terms of the CRISP contracts. These additional reserves are reported in the table below under the row labeled Changes in Reserves from Current Operations. Second, the beginning balance in working capital and operating reserves was $1.9M higher than budgeted due to expense and fixed asset under runs in 2014. The actual 2015 beginning balance in working capital and operating reserves was $7.46M, based upon audited 2014 year-end results. The balances in the Future Obligations Reserve, the Operating Contingency Reserve, the System Operator Reserves, and CRISP Reserves as of March 31st, were approximately $3.35M, $2.5M, $1.16M, and $4.97M respectively.

				March 31, 2015 Reserve Balances				
	2015 Actual	2015 Budget	Variance - Actual to Budget	Future Obligations Reserve	Operating Contingency Reserve	System Operator Reserves	CRISP Reserves***	Assessment Stabilization Reserve
Beginning Working Capital and Operating Reserves - 1/1/2015	**7,460,907**	**5,573,225**	**1,887,682**	**3,569,492**	**2,011,402**	**1,294,513**	**585,500**	**-**
Proceeds from Financing Activities (non-current portion only)	-		-		-			
Debt Service	(105,417)	(223,416)	117,999		(105,417)			
Change in Reserves from Current Year Operations	4,859,572	567,936	4,291,636		615,367	(138,902)	4,383,107	
Other adjustments to reserves**	(248,090)	(80,555)	(167,536)	(224,130)	(23,960)		-	
Reserve Balance	**11,966,973**	**5,837,191**	**6,129,782**	**3,345,362**	**2,497,392**	**1,155,611**	**4,968,607**	**-**

**Represents transactions recorded only on the Statement of Financial Position (balance sheet) and do not impact the Statement of Activities (income statement), including recording of capitalized leases, amortization of future obligations and funding the 457f plan.

***Represents 2015 CRISP funding billed, net of 2014 credits issued for budget under runs.

As of March 31st, the projected use of operating reserves includes $597.3k for leasehold improvements, $140.75k to study the EPA Clean Power Plan, and $50k for higher than budgeted costs associated with GridEx III. As explained above, the use of reserves to fund leasehold improvements was approved by the Finance and Audit Committee in 2014. All necessary corporate authorizations have been obtained for reserve funding of these projects. The projected year-end reserve balances reflected in the following table do not include funding to commence implementation of a document management program in 2015. Further information regarding the document management program, including funding requirements, is set forth under agenda item 2 of the Standards Oversight and Technology Committee May 6, 2015 agenda and agenda item 5 of the Finance and Audit Committee's May 6, 2015 agenda. Primarily due to higher

than projected starting year reserve balances, we expect sufficient reserves will be available to fund the projected 2015 costs of the document management program without materially impacting overall operating reserve levels. The projected year end balances in the Future Obligations Reserve, the Operating Contingency Reserve, the System Operator Reserves, and CRISP Reserves, are approximately $3.1M, $2.65M, $826.5k, and $600.0k respectively.

				2015 Projected Year End Reserve Balances				
	2015 Projection as of 3/31/2015	2015 Budget	Variance - Projection to Budget	Future Obligations Reserve	Operating Contingency Reserve	System Operator Reserves	CRISP Reserves***	Assessment Stabilization Reserve
Beginning Working Capital and Operating Reserves - 1/1/2015	**7,460,907**	**5,573,225**	**1,887,682**	**3,569,492**	**2,011,402**	**1,294,513**	**585,500**	**-**
Proceeds from Financing Activities (non-current portion only)	1,266,667	1,266,667	-		1,266,667			
Debt Service	(421,667)	(893,664)	471,997		(421,667)			
Change in Reserves from Current Year Operations	(634,322)	721,956	(1,356,278)	-	(180,778)	(468,047)	14,503	
Other adjustments to reserves**	(519,698)	(322,218)	(197,480)	(493,418)	(26,280)			
Reserve Balance	**7,151,887**	**6,345,966**	**805,922**	**3,076,074**	**2,649,344**	**826,466**	**600,003**	**-**

**Represents transactions recorded only on the Statement of Financial Position (balance sheet) and do not impact the Statement of Activities (income statement), including recording of capitalized leases, amortization of future obligations and funding the 457f plan.

***Represents 2015 CRISP funding billed, net of 2014 credits issued for budget under runs.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Statement of Activities and Fixed Assets Budget
(Unaudited)
For the period ended 03/31/2015

	2015 Actual	2015 Budget	2015 Variance Over(Under)	%	2015 Projection	2015 Annual Budget	2015 Projected Variance from Budget Over(Under)	%
Funding								
Assessments	13,827,094	13,827,094	-		55,308,375	55,308,375	-	
Penalties	1,155,000	1,155,000	-		1,155,000	1,155,000	-	
Third-Party Funding (CRISP)	4,965,860	2,235,898	2,729,962		7,228,140	8,943,589	(1,715,449)	
Testing	383,587	417,504	(33,917)		1,670,000	1,670,000	-	
Services & Software	17,000	12,506	4,494		50,000	50,000	-	
Workshop Fees	44,725	52,000	(7,275)		241,300	241,300	-	
Interest	2,209	752	1,457		4,158	3,000	1,158	
Miscellaneous	-	-	-		-	-	-	
Total Funding	20,395,475	17,700,754	2,694,721	15.2%	65,656,973	67,371,264	(1,714,291)	-2.5%
Expenses								
Personnel Expenses								
Salaries	6,968,591	6,895,175	73,416		27,388,831	27,580,676	(191,845)	
Payroll Taxes	781,395	707,701	73,694		1,806,463	1,673,628	132,835	
Employee Benefits	825,011	886,786	(61,775)		3,380,013	3,547,177	(167,164)	
Savings & Retirement	699,550	826,930	(127,380)		2,805,104	3,001,829	(196,725)	
Total Personnel Expenses	9,274,547	9,316,593	(42,046)	-0.5%	35,380,411	35,803,311	(422,900)	-1.2%
Meeting Expenses								
Meetings	231,292	276,542	(45,250)		1,051,303	1,050,000	1,303	
Travel	565,509	550,824	14,685		2,348,831	2,203,395	145,436	
Conference Calls	74,232	78,193	(3,961)		358,797	312,751	46,046	
Total Meeting Expenses	871,033	905,559	(34,526)	-3.8%	3,758,931	3,566,146	192,785	5.4%
Operating Expenses								
Consultants and Contracts	2,519,192	3,995,150	(1,475,958)		13,509,173	14,311,466	(802,293)	
Rent & Improvements	701,577	746,939	(45,362)		2,987,777	2,987,777	-	
Office Costs	918,824	895,793	23,031		3,552,416	3,583,328	(30,912)	
Professional Services	497,060	652,826	(155,766)		2,672,280	2,611,280	61,000	
Miscellaneous	5,710	9,125	(3,415)		39,500	36,500	3,000	
Depreciation	467,632	583,253	(115,622)		2,438,110	2,333,006	105,103	
Total Operating Expenses	5,109,995	6,883,086	(1,773,091)	-25.8%	25,199,255	25,863,357	(664,102)	-2.6%
Other Non-Operating Expenses	5,972	32,750	(26,778)	-81.8%	75,000	131,000	(56,000)	-42.7%
Total Expenses	15,261,548	17,137,988	(1,876,440)	-10.9%	64,413,597	65,363,815	(950,217)	-1.5%
Net Change in Assets	**5,133,927**	**562,766**	**4,571,161**	**812.3%**	**1,243,376**	**2,007,449**	**(764,074)**	**-38.1%**
Fixed Assets								
Depreciation	(467,632)	(583,253)	115,622		(2,438,110)	(2,333,006)	(105,103)	
Computer & Software	460,465	492,250	(31,785)		3,158,757	3,153,500	5,257	
Furniture & Fixtures	-	-	-		-	-	-	
Equipment	148,320	85,833	62,487		559,743	465,000	94,743	
Leasehold Improvements	133,202	-	133,202		597,307	-	597,307	
Incr(Dec) in Fixed Assets	**274,355**	**(5,170)**	**279,525**	**-5406.7%**	**1,877,697**	**1,285,494**	**592,204**	**46.1%**
							-	
Total Budget (Expenses plus Incr(Dec) in Fixed Assets)	**15,535,903**	**17,132,818**	**(1,596,915)**	**-9.3%**	**66,291,295**	**66,649,308**	**(358,014)**	**-0.5%**
FTE's	**188.00**	**192.35**	**(4.35)**	**-2.3%**	**190.73**	**192.30**	**(1.57)**	**-0.8%**

NORTH AMERICAN ELECTRIC RELIABILITY COPORATION
STATEMENT OF FINANCIAL POSITION
(Unaudited)

	Unaudited 3/31/2015	Audited 12/31/2014	Working Capital and Operating Reserves 3/31/2015	Working Capital and Operating Reserves 12/31/2014
ASSETS				
Cash	37,734,536	38,904,711	37,734,536	38,904,711
Accounts receivable, net of allowance for uncollectible accounts of 0 and 62,573 in 2014 and 2013	25,156,002	5,059,002	25,156,002	5,059,002
Prepaid expenses and other current assets	920,226	756,727	920,226	756,727
Security deposit	125,416	99,136		
Employee Fiduciary - 457b	522,756	522,756		
457(f) Non-Qualified Def Comp	171,200	-		
Property and equipment	6,203,720	5,929,365		
Total Assets	70,833,856	51,271,697		
LIABILITIES AND NET ASSETS				
Liabilities				
Current Portion				
Accounts payable and accrued expenses (includes vacation accrual)	6,306,175	4,970,198	(6,306,175)	(4,970,198)
Accured incentive compensation	1,076,177	4,054,329	(1,076,177)	(4,054,329)
Deferred rent-current	246,442	249,269	(246,442)	(249,269)
Deferred compensation - current	14,257	14,257	(14,257)	(14,257)
Capital lease obligations - current	56,457	56,457	(56,457)	(56,457)
Accrued retirement liabilities	693,207	1,907,562	(693,207)	(1,907,562)
Debt service - current portion	421,667	421,667	(421,667)	(421,667)
Deferred income	19,274,440	6,228,959	(19,274,440)	(6,228,959)
Deferred revenue - penalties	-	-	-	-
Deferred revenue - CRISP	-	3,953,379	-	(3,953,379)
Regional assessments	20,544,968	11,438,455	(20,544,968)	(11,438,455)
Total Current Portion	48,633,791	33,294,532		
Long-Term Portion				
Deferred compensation[1]	785,766	783,446		
Long-Term Debt	351,389	456,806		
Deferred Rent-non-current	3,516,562	3,569,492		
CRISP Insurance Reserve	500,000	500,000		
Capital lease obligations - non-current	216,481	216,481		
Total Long-Term Portion	5,370,198	5,526,224		
Total Liabilities	54,003,988	38,820,756		
Net Assets - unrestricted	13,619,868	8,485,941		
Net Assets - restricted	3,210,000	3,965,000	(3,210,000)	(3,965,000)
Total Liabilities and Net Assets	70,833,856	51,271,697	11,966,973	7,460,907
[1]Includes 457b liability, life insurance for former executive, and retiree medical				
Working Capital and Operating Reserves	**11,966,973**	**7,460,907**		

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)**	**Docket No. RC15-1-000**
	)	

MOTION TO INTERVENE AND COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND WESTERN ELECTRICITY COORDINATING COUNCIL

Pursuant to Rules 212 and 214 of the Federal Energy Regulatory Commission's (the "Commission" or "FERC") Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.214, the North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") move to intervene and comment on the Application of Southern California Edison Company ("SCE") for Factual Determination That the Indicated 115 kV Facilities Are Used In Local Distribution ("Application") filed on April 16, 2015 in the above-referenced docket.[1]

In its Application, SCE seeks to establish that "certain 115 kV facilities are not part of the Bulk Electric System ("BES"),"[2] and that it is appropriately "exempt[ing] these facilities from the Bulk Electric System by filing the instant Application rather than pursuing other less durable procedural avenues."[3] SCE has requested a Commission order in response to its Application no later than December 2015.[4]

[1] *See Southern California Edison Company Application for Factual Determination That the Indicated 115 kV Facilities Are Used In Local Distribution*, Docket No. RC15-1-000 (April 16, 2015) ("SCE Application").
[2] Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards, available at* http://www.nerc.com/files/Glossary_of_Terms.pdf ("NERC Glossary").
[3] *Id.* at 1.
[4] *Id.* at 3.

NERC and WECC agree that SCE's application is an appropriate means to determine that the indicated facilities are local distribution. As the Commission noted in Order No. 743, "to the extent that any individual line would be considered to be local distribution, that line would not be considered to be part of the [BES]."[5] Therefore, NERC and WECC are not contesting the avenue in which SCE is seeking a determination of local jurisdiction (i.e., directly with FERC). Rather, NERC and WECC's comments focus specifically on reliability factors relevant to determine whether SCE's 115 kV facilities should be classified as local distribution and the need for more information regarding the Facilities in question before an accurate determination can be made regarding the material impact of the Facilities at issue on the BES.

[5] Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure, 141 FERC ¶ 61,236, Order No. 743 (2012), at P. 39.

I. NOTICES AND COMMUNICATIONS

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II. BACKGROUND

The Commission certified NERC as the Electric Reliability Organization ("ERO") for the purpose of establishing and enforcing Reliability Standards for the Bulk-Power System ("BPS") in the United States.[6] On April 19, 2007, the Commission approved delegation agreements

[6] *North American Electric Reliability Council, Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

between NERC and eight Regional Entities, including a delegation agreement between NERC and WECC.[7] Pursuant to its delegation agreement, NERC delegated to WECC the authority to enforce mandatory Reliability Standards within the WECC region.

NERC's BES Definition is an integral part of the NERC Reliability Standards and is included in the NERC Glossary of Terms. The BES Definition consists of a "core" definition and a list of configurations of facilities that would be included or excluded from the "core" definition, i.e. Inclusions and Exclusions. Additionally, a case-by-case exception process, to add elements to, and remove elements from, the BES adds transparency and uniformity to the process of determining what constitutes the BES.

Separate from the Exclusion process laid out within the NERC Rules of Procedure, an entity with Facilities falling within the "core" definition or Inclusions may file a jurisdictional application to the Commission as to whether certain Elements are local distribution. This application does not require a prior determination under the NERC Exception process. Rather, the two processes are independent paths for seeking different types of relief. The NERC Exception process grants an exception from application of the BES Definition, while an application to FERC for an individual determination excludes local distribution facilities from FERC's regulatory jurisdiction even if those facilities are BES Elements under the BES Definition.[8]

On April 16, 2015, SCE filed its Application seeking to establish the following: 1) that certain SCE 115 kV facilities are not part of the BES;[9] and 2) that SCE has appropriately sought

[7] *North American Electric Reliability Council, North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, order on reh'g, 120 FERC ¶ 61,260 (2007).
[8] Order No. 773-A, 143 FERC ¶ 61,053 at PP 83-94.
[9] SCE Application at p. 1.

a determination that these facilities are not BES Elements by filing the instant Application rather than through the NERC Exception process.[10]

SCE relies on its application of the Seven Factor Test and the Mansfield test to support its assertion that "the specific design, function, and use" of the facilities supports its claim that the facilities should be designated as local distribution.[11] In addition, SCE provides the results from a technical, "TPL-like" analyses[12] it undertook to determine that the 115 kV facilities at issue have no material impact on the reliability of the BPS. According to SCE, these analyses studied the "loss of all local generation within a system…, steady-state thermal loading and voltage deviation analysis, dynamic frequency, voltage, angular stability analysis, and tests for positive reactive power margin."[13]

III. MOTION TO INTERVENE

NERC has a substantial interest in this proceeding, as it is the certified ERO under section 215 of the Federal Power Act.[14] As the ERO, NERC's mission is to improve the reliability and security of the BPS in North America.[15] No other party can adequately comment with the same level of technical expertise on the reliability of the BPS as NERC. WECC is the Regional Entity for the Western Interconnection, which includes the SCE facilities at issue in its Application. Therefore, it is in the public interest to permit this intervention.

IV. COMMENTS

Neither NERC nor WECC contest that SCE has appropriately applied to the Commission directly for a determination that the facilities at issue are local distribution, which would be

[10] *Id.*
[11] *Id.* at p. 3.
[12] *Id. at* p. 36.
[13] *Id.* at p. 37.
[14] *Supra* n.4.
[15] *See id.*

excluded from Commission jurisdiction. The comments of NERC and WECC focus on the reliability of the BPS and the Western Interconnection and specifically on whether SCE's filing is sufficient to determine if, in fact, SCE uses the Facilities only in the local distribution of energy and whether the Facilities are important elements in support of reliability of the BPS.

The Commission has acknowledged that an analysis determining whether facilities are local distribution begins with application of the BES Definition.[16] In its Application, SCE applies the BES Definition and asserts that although the Facilities fall within the core definition, its Facilities are in fact local distribution. SCE uses the Seven-Factor Test[17] and Mansfield test[18] to analyze whether its Facilities are local distribution, which the Commission noted in Order No. 773 would be relevant to the Commission in making a determination of whether facilities are in fact local distribution.[19] However, as the Commission also recognized, "the factors identified in the Seven Factor Test are not exclusive when determining whether an element is used for local distribution . . . [and] the Seven Factor Test does not resolve all possible issues."[20] The Commission recognized that "there may be *other factors* that should be taken into account in particular situations."[21] NERC and WECC respectfully suggest that these "other factors" should consider whether Facilities purportedly only used in local distribution impact the reliability of the BPS.[22] Thus, in addition to the Seven Factor Test and Mansfield tests, the Commission may also consider whether SCE has provided adequate information to address concerns about the impact to reliability.

[16] Order No. 773, 141 FERC ¶ 61,236 at P 67.
[17] SCE Application at p. 17-19.
[18] *Id.* at p. 19-21.
[19] Order No. 773, 141 FERC ¶ 61,236 at P 155 n.139, *citing* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at P 71 (emphasis added).
[20] *Id.* at P 71.
[21] *Id.* (emphasis added).
[22] *See* Order No. 743, 133 FERC ¶ 61,150 at P 37.

The studies SCE performed may not wholly encompass the entire scope of conditions the Commission might consider to determine the impact on the reliability of the BPS, especially in light of the significance placed on reliability of the BPS in recent years with the creation of the ERO. SCE argues in its Application that several of the Facilities at issue in its Application would merely be a re-affirmation of previous decisions the Commission has made regarding the same Facilities in various contexts, recognizing their unique characteristics and use as part of the local distribution system.[23] However, Order No. 888, which SCE points to as a basis to continue to exclude some of its Facilities from local distribution, was issued in 1996 and affirmed in 2002 – four years before NERC was certified as the ERO for the United States,[24] and *nine years* before the Commission approved the revised definition of the BES.[25]

Since Order No. 888, the Facilities, load, and generation in the SCE service territory at issue in its Application have grown substantially. These areas now contain approximately 4,479 MW of load, with additional load growth also forecasted.[26] Additionally, these areas now have at least 1435 MW of generation, of which at least 772 wind, and 158 is cogeneration.[27] While SCE uses "TPL-like studies" to demonstrate that these facilities have no impact on reliability,[28]

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[23] SCE Application at p. 17, citing to *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats & Regs. ¶31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶31,048, *order on reh'g.*, Order No. 888-B, 81 FERC ¶61,248 (1997), *order on reh'g.*, Order No. 888-C, 82 FERC ¶61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (.D.C. Circuit 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[24] *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶61,062 (2006).

[25] *See* Order No. 773.

[26] *See, e.g.*, Prepared Direct Testimony of Jonathan M. Shearer on Behalf of Southern California Edison Company (Shearer Direct Testimony), pp. 13-17 (CEII Version).

[27] *See id.*

[28] As part of these studies, SCE uses the WECC BES Inclusion Guideline ("Guideline") to support its conclusion that its facilities do not impact the BPS reliability. WECC notes that the industry did not create or intend to use the Guideline for this purpose. The Guideline contains situations where Transmission Planners and Planning Coordinators should give consideration for including sub-100 kV facilities into the BES because of potential BES reliability impacts. WECC members' intent was not to provide guidance for when entities should exclude BES facilities from the BPS.

NERC and WECC assert there may be additional studies and information needed, and more factors to consider, as potentially identified below. Even assuming the technical analyses SCE performed are the appropriate initial set of tests, some important questions remain unanswered or incompletely answered at this time. The following is a general summary of some (not all-inclusive) of the information that NERC and WECC believe SCE should provide before the Commission makes a determination of the impact of the Facilities at issue on the reliability of the BPS and their status as local distribution:

1. A demonstration of the current fault contributions to the BPS from the systems for which SCE is requesting the local distribution designation.

2. A discussion of the potential reliability impact on the BPS for the failure of the local network protection systems, particularly, the protection systems associated with the 500/115 kV and 230/115 kV transformers connected to these networks.

3. An explanation of how the generation and reactive devices (shunt capacitors) are used to provide voltage support or control of the BPS. In Order No. 773, the Commission stated that, if the generator is necessary for the operation of the interconnected transmission network, it is appropriate also to include the generator interconnection facility operating at or above 100 kV that delivers the generation to the BES.

4. The study assumptions SCE uses in selecting the power flow base cases, system conditions, path transfers, as related to the associated facility ratings and nomograms, seasonal conditions, inertia requirements, and emergency ratings, etc., with an explanation of how those assumptions affect the study results and conclusions.

5. Whether SCE used the WECC composite load model in the power flow and stability analyses, and if not, why. At least one of the local areas concerned is susceptible to fault-induced delayed voltage recovery ("FIDVR"), and the composite load model is a better assumption to use in such areas.[29]

6. Whether SCE conducted post-transient studies or voltage stability studies, with an explanation of whether these local systems could become VAR deficient when generator operators do not dispatch local traditional generation resources due to economic conditions.

[29] *See Composite Load Model for Dynamic Simulations Report 1.0, Western Electricity Coordinating Council's Model and Validation Work Group,* June 12, 2012.

7. An explanation of how voltages can be controlled in these areas under light-load conditions, light transfers across the BPS lines in the area, and high renewable generation levels.

8. A discussion of the potential effect of the magnitude of the load, on end-use customers (~600,000 people) all served through one substation.[30]

Neither NERC nor WECC have sufficient information at this time to answer these questions and make an adequate recommendation to the Commission concerning SCE's request for a local distribution designation. Accordingly, NERC and WECC believe additional information is necessary to establish a full and complete record before an accurate determination is made regarding the impact of the facilities at issue on the BPS.

NERC and WECC also have additional concerns as to the potential aggregate as well as individual system-wide risks posed by a decision to designate these Facilities as local distribution. As the Commission has stated in its Risk-Based Registration Order issued on March 19, 2015 when referring to registration matters, consideration of the aggregate risk and possible cumulative effect is "fundamental" to ensuring that decisions do not lead to increased risk to BPS reliability.[31] Regardless of the method an entity may choose to be qualified as local distribution, the reliability of the BPS should remain a paramount concern.

[30] Exhibit SCE-1, p. 15.
[31] *Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing*, 150 ¶ 61,213 at P 68 (2015).

V. CONCLUSION

WHEREFORE, NERC and WECC respectfully request that the Commission grant this motion for leave to intervene and issue an order consistent with the comments herein.

Respectfully submitted,

/s/ Holly A. Hawkins
Counsel for the North American Electric Reliability Corporation

/s/ Ruben H. Arredondo
Counsel for the Western Electricity Coordinating Council

Date: May 18, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding. Dated at Washington, D.C. this 18th day of May 2015.

/s/ Holly A. Hawkins
Holly A. Hawkins

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May 29, 2015

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: North American Electric Reliability Corporation
Docket No. RR15-_-000
Report of Comparisons of Budgeted to Actual Costs for 2014 for NERC and the Regional Entities

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) hereby submits the "North American Electric Reliability Corporation's Report of Comparisons of Budgeted to Actual Costs for 2014 for NERC and the Regional Entities." This filing also includes a 2014 actual cost-to-budget report for Peak Reliability.

This filing consists of: (1) this transmittal letter, (2) the narrative text of the filing, which follows this transmittal letter, and (3) Attachments 1 through 11. The Table of Contents to the narrative text list the 11 attachments.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Owen E. MacBride
Owen E. MacBride

Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
Before the
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)** **)**	**Docket No. RR15-__-000**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION'S REPORT OF COMPARISONS OF BUDGETED TO ACTUAL COSTS FOR 2014 FOR NERC AND THE REGIONAL ENTITIES

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May 29, 2015

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IV.	COMPARISON OF ACTUAL COSTS TO BUDGET FOR THE YEAR ENDED DECEMBER 31, 2014 – PEAK RELIABILITY, INC.	10
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ATTACHMENTS:

Attachment 1: North American Electric Reliability Corporation – 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements

Attachment 2: Florida Reliability Coordinating Council, Inc. – 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements

Attachment 3: Midwest Reliability Organization – 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements

Attachment 4: Northeast Power Coordinating Council, Inc. – 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements

Attachment 5: ReliabilityFirst Corporation – 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements

Attachment 6: SERC Reliability Corporation – 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements

Attachment 7: Southwest Power Pool Regional Entity – 2014 Actual Cost-to-Budget Comparison; Audited Financial Statements of Southwest Power Pool, Inc.

Attachment 8: Texas Reliability Entity, Inc. – 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements

Attachment 9: Western Electricity Coordinating Council – 2014 Actual Cost-to-Budget Comparison (based on unaudited financial statements)

Attachment 10: Peak Reliability, Inc. – 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements

Attachment 11: Metrics Concerning Administrative Costs in 2014 NERC and Regional Entity Budgets and Actual Costs

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") respectfully submits this filing to provide comparisons of actual to budgeted costs for the year 2014 for NERC and the eight Regional Entities.[1] NERC is also submitting a comparison of actual to budgeted costs for 2014 for Peak Reliability, Inc. ("Peak"). The Commission originally directed NERC to file, each year, comparisons of actual to budgeted costs for the preceding year, in an order issued October 18, 2007 concerning the 2008 business plans and budgets of NERC and the Regional Entities.[2] In several subsequent orders, the Commission has clarified and expanded upon the information to be included in the annual actual-to-budget cost comparisons filings.

The following information is provided in this filing:

- A comparison of the actual funding received and costs incurred by NERC and each Regional Entity, and by Peak, for statutory and (where applicable) non-statutory activities for the year ended December 31, 2014, to the budgets of NERC and each Regional Entity for that year, with explanations of significant actual cost-to-budget variances.
- Audited financial statements of NERC, and of each Regional Entity except WECC, for the year ended December 31, 2014.[3]
- Tables showing metrics concerning NERC and Regional Entity administrative costs in their 2014 budgets and actual results.

This filing includes the following attachments:

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[1] The eight Regional Entities are the Florida Reliability Coordinating Council, Inc. ("FRCC"), Midwest Reliability Organization ("MRO"), Northeast Power Coordinating Council, Inc. ("NPCC"), ReliabilityFirst Corporation ("ReliabilityFirst"), SERC Reliability Corporation ("SERC"), Southwest Power Pool, Inc. Regional Entity ("SPP RE"), Texas Reliability Entity, Inc. ("Texas RE"), and Western Electricity Coordinating Council ("WECC").

[2] *North American Electric Reliability Corporation, Order Conditionally Accepting 2008 Business Plan and Budget of the North American Electric Reliability Corporation and Ordering Compliance Filings*, 121 FERC ¶ 61,057 (2007) ("*2008 ERO Budget Order*").

[3] As explained below, WECC's audited financial report was not completed as of the date of this filing; WECC's audited financial report is expected to be available in June 2015 and will be provided to the Commission in a supplemental filing.

Attachment 1: 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements for NERC.

Attachment 2: 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements for FRCC.

Attachment 3: 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements for MRO.

Attachment 4: 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements for NPCC.

Attachment 5: 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements for ReliabilityFirst.

Attachment 6: 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements for SERC.

Attachment 7: 2014 Actual Cost-to-Budget Comparison for SPP RE and Audited Financial Statements for Southwest Power Pool, Inc.

Attachment 8: 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements for Texas RE.

Attachment 9: 2014 Actual Cost-to-Budget Comparison (based on unaudited financial statements) for WECC.

Attachment 10: 2014 Actual Cost-to-Budget Comparison and Audited Financial Statements for Peak.

Attachment 11: Metrics Concerning Administrative Costs in 2014 NERC and Regional Entity Budgets and Actual Costs

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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III. COMPARISONS OF ACTUAL COSTS TO BUDGETS FOR THE YEAR ENDED DECEMBER 31, 2014 – NERC AND REGIONAL ENTITIES

As noted above, in the *2008 ERO Budget Order*, the Commission directed NERC to make annual filings comparing the NERC and Regional Entity budgets to actual costs incurred in the preceding year, "in sufficient detail and with sufficient explanations for the Commission to determine, by program area, the reasons for deviations from the budget and the impacts of those deviations."[4] In its June 19, 2008 Order addressing NERC's April 1, 2008 compliance filing to the *2008 ERO Budget Order*, the Commission provided additional direction concerning the presentation of the annual filings comparing NERC's and the Regional Entities' actual to budgeted expenditures:

> 37. To promote consistency and transparency, the Commission directs the use of certain practices and formats in future true-up filings. In particular, Regional Entities must provide a cover letter discussing major areas of actual cost-to-budget variances for all of the Regional Entity's statutory programs in the aggregate. Regional Entities should also follow NERC's template for the presentation of actual costs and budgeted costs on a program-by-program and line-item basis. Significant variances must be explained on a line-item basis with enough particularized information to clearly support each such variance. Regional Entities should refrain from using generic, program area summaries to support significant variances. The cause for each such variance should therefore be clear on its face. Further, each Regional Entity must provide an explanation of the allocation methods it used to allocate indirect costs to the direct statutory program or functional areas, as well as any allocation between any statutory and non-statutory activities.
>
> 38. Cash reserves are meant to handle expenses which exceed the amount budgeted, as well as unforeseen events that could occur at any time. However, in the future, the Commission expects NERC and the Regional Entities to justify the use of cash reserves as variances in the April true-up. Cash reserves should not become a means to fund expected projects outside of the budget approval process. The Commission expects that as NERC and the Regional Entities develop experience in planning and functioning under their budgets the amounts and number of variance will decrease. In addition, the Commission expects that with

[4] *2008 ERO Budget Order* at P 23.

experience, the explanations for the variances will improve.[5]

In addition, although the following directive in the *2008 ERO Budget Order* was expressly applicable to NERC's compliance filing comparing actual expenses to budgets for the year ended December 31, 2007 for NERC and the Regional Entities, NERC has treated the directive as intended to apply to the annual filings comparing actual expenses to budgets for future years as well:

> 66. . . . [T]he Commission reminds NERC and the Regional Entities that, to the extent funding identified as statutory is used to fund non-statutory activities, those funds must be reimbursed (e.g., to load serving entities or to statutory expenditures). NERC is directed to inform the Commission in the . . . compliance filing the extent to which this has occurred and document that the funds have been or will be reimbursed.

The comparisons of 2014 actual-to-budget funding and expenditures for NERC and the Regional Entities are provided in **Attachments 1 through 9**, as follows:

- **Attachment 1:** NERC
- **Attachment 2:** FRCC
- **Attachment 3:** MRO
- **Attachment 4:** NPCC
- **Attachment 5:** ReliabilityFirst
- **Attachment 6:** SERC
- **Attachment 7:** SPP RE
- **Attachment 8:** Texas RE
- **Attachment 9:** WECC

Each Attachment also includes the respective entity's audited financial report for the year ended December 31, 2014, as prepared by its independent public accounting firm, with the exception of the Attachment for WECC. WECC's outside auditors were unable to complete their audit of

[5] *North American Electric Reliability Corporation, Order Conditionally Accepting Compliance Filing*, 123 FERC ¶61,282 (2008) ("*June 19, 2008 Budget Compliance Order*"), PP 37-38.

WECC's 2014 financial statements in time for inclusion in this filing, due to staffing shortages experienced by the auditors. WECC expects to receive its audited financial report for 2014 from its outside auditors in June 2015, and, when received, NERC will file WECC's audited 2014 financial statements with the Commission in a supplemental filing.

The comparisons provided in **Attachments 1** through **9** conform to the Commission's directives as quoted above:

- Each comparison contains a cover letter or an overview or summary section identifying overall actual-to-budget variances in Funding and total Expenses and in major Expense categories, and discussing reasons for major areas of actual cost-to-budget variances.
- Each comparison contains a summary table, prepared using a NERC-supplied template, showing the entity's 2014 budget, 2014 actual amounts, and the variance, for major line-item categories of Funding and Expenses.
- For those entities that engaged in both statutory and non-statutory activities in 2014, the comparisons include separate summary tables for statutory programs and non-statutory activities, prepared using the NERC-supplied template, showing the entity's 2014 budget, 2014 actual amounts, and the variance, for major line-item categories of Funding and Expenses.[6]
- The comparisons include individual tables, also prepared using a NERC-supplied template, showing 2014 budget, 2014 actual amounts, and the variance, for major line-item categories of Funding and Expenses, for each of the statutory programs[7] (direct costs) and the overhead functions[8] (indirect costs). Explanations for significant line-item actual-to-budget variances are provided following each table, either below the table or on the immediately following page(s).[9]

[6] FRCC, NPCC, Texas RE and WECC had non-statutory activities in 2014 and each has provided summary tables for statutory and non-statutory activities. NERC, MRO, ReliabilityFirst, SERC and SPP RE did not have non-statutory activities in 2014 (although SPP RE's parent organization, Southwest Power Pool, Inc. had non-statutory activities).

[7] Statutory programs encompass Reliability Standards, Compliance Operations and Enforcement, Reliability Assessment and Performance Analysis, Training, Education and Operator Certification, and Situation Awareness and Infrastructure Security (including Critical Infrastructure Protection).

[8] Committees and Member Forums, General and Administrative, Legal and Regulatory, Information Technology, Human Resources, and Accounting and Finance. Some of the Regional Entities report budget and actual expenditure information for some or all of the overhead functions on a combined basis, in order to protect the confidentiality of compensation information for departments that have a limited number of staff members.

[9] Generally, explanations have been provided for line-item variances that are greater than +/- 10% of the budgeted amount and greater than $10,000 over or under the budgeted amount. For ease of formatting the

The Attachments also address (generally in the cover letter or overview section) (i) where applicable, whether any statutory funds were used in 2014 for non-statutory activities (neither NERC nor any Regional Entity reports using statutory funds for non-statutory activities during 2014); (ii) the impact of the entity's 2014 results on its working cash reserve for statutory programs (*e.g.*, whether working cash reserves were used to fund expenditures during 2014)[10]; (iii) how indirect costs were allocated to the direct statutory programs or functions; and (iv) where applicable, whether, and if so how, costs were allocated between statutory programs and non-statutory activities in 2014.

NERC has provided additional information in its 2014 report in **Attachment 1** on (1) actual cost to budget variances for Consultants and Contracts expense, and (2) an analysis and comparison of the major sources of changes in its working capital and operating reserves for 2014, as budgeted and per actual results. The analysis of working capital and operating reserves includes a breakdown of the changes in working capital and operating reserves due to 2014 budgeted operations and to differences in actual funding or expenditures from amounts budgeted, including unbudgeted or above-budget expenditures funded from the Known Contingency Reserve or the Unknown Contingency Reserve. The table on page 4 of **Attachment 1** shows the actual cost to budget variances for Consultants and Contracts expense for 2014 by NERC program area, and is followed by a narrative discussion of the reasons for actual cost-to-budget variances for Consultants and Contracts expense in each program area. The analysis of changes

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tables, the placement of these explanations in the report has been changed slightly from prior years' reports, so that the explanations are now shown beneath the applicable table or on the page(s) immediately following the table, rather than adjacent to the line items to which they relate.

[10] The summary comparison tables for total entity and (where applicable) statutory and non-statutory activities show the "Change in Working Capital" (or in "Operating Reserves") for the 2014 Actual Funding and Expenditures. A positive "Change in Working Capital" means the entity's total Actual Funding exceeded its total Actual Expenditures for the year 2014; therefore, it was not necessary for the entity to use a portion of its cash reserves balance at December 31, 2013 to fund 2014 expenditures.

in working capital and operating reserves is provided on pages 8 of **Attachment 1**, including a table which shows changes in reserves from current year (2014) operations for the Known Contingency Reserve, Unknown Contingency Reserve, and System Operator Reserve. In addition, in its 2014 report, NERC has provided an actual cost-to budget comparison of 2014 Board of Trustees expenses, detailed by Meetings and Travel Expense (Quarterly Board Meetings and Trustee Travel expense) and Professional Services (Independent Trustee Fees and Trustee Search Fees). *See* page 6 of **Attachment 1**.

Because the NERC and Regional Entity reports in each Attachment identify and discuss major areas of actual cost-to-budget variances, and the individual tables for each direct statutory program and each indirect cost function contain specific explanations of significant variances on a line-item basis, a detailed, entity-by-entity discussion of the actual-to-budget variances experienced in 2014 by NERC and individual Regional Entities is not provided here. However, the list below describes several recurring drivers of actual cost-to-budget variances experienced by NERC and the Regional Entities in 2014, as identified by NERC's review of the comparisons.

- A number of entities[11] experienced under-budget variances in Salary Expense and related Personnel Expenses (Payroll Taxes, Employee Benefits and Retirement Expense), in one or more program areas, due to being unable to fill budgeted positions, due to higher vacancy rates (*i.e.*, higher number of unfilled positions), or to filling budgeted positions later in the year, than was assumed in the budget. Additionally, having fewer personnel on staff than budgeted was a factor tending to reduce Meetings and/or Travel Expense below the budgeted amounts.[12]
- In some instances, due to the difficulty in filling budgeted positions, the entity may have found it necessary to incur costs for temporary staffing services while budgeted

[11] The term "entities" is used in this discussion to include NERC as well as Regional Entities.

[12] In the development of their annual budgets, NERC and some of the Regional Entities have begun to address this "vacant position" variance issue by including an "attrition factor" or "labor float factor" into their budget calculations. The attrition factor recognizes that, as in any organization, a portion of the budgeted positions will be vacant during a part of the year due to delays in filling new or vacant positions and unexpected/unbudgeted departures of existing employees. Nonetheless, variances between the projected and actual attrition factor or labor float factor can result in variances between budgeted and actual Personnel Expenses.

positions were vacant.

- In order to address unfilled positions or emergent needs in particular program areas, some entities transferred one or more employees from one program area to another during 2014, or had shared FTEs who spent a greater portion of their time working in one program area and a lesser portion of time in another program area than was reflected in the budget. This resulted in actual cost-to-budget variances in Personnel Expenses and related Meeting and Travel expenses for the program areas involved in such transfers, although not necessarily for the entity as a whole.
- The inability to fill budgeted positions as planned also resulted in some instances in higher-than budgeted Consultants & Contracts expense, due to either or both the need to use consultants or contractors to perform work that would have been done by employees, or the need to make greater use than budgeted of personnel recruiting services and search firms.
- On the other hand, some entities were able to spend less on Consultants and Contracts than budgeted, as a result of having work budgeted to be performed by contractors and consultants handled by internal staff of the entity. As some entities have increased their staffing over time, they have seen less need to use outside services, due to increased in-house staff capabilities.
- Generally, NERC and the Regional Entities allocate Indirect Expenses to the direct statutory programs on the basis of numbers of FTEs in each statutory program. Therefore, due to differences in actual versus budgeted FTEs during the year in individual statutory programs, some entities experienced variances from budget in the amounts of Indirect Expenses allocated to the individual direct statutory programs.
- Some entities experienced higher or lower Employee Benefits expenses than budgeted due to actual renewal rates from services providers for their health and medical benefits programs being different than projected at the time of budget preparation.
- Some entities experienced lower than budgeted Employee Benefits expenses due to decisions by employees not to participate in the entity's medical benefits program. In some cases employees elected to stay on the health and medical programs of previous employers or of their spouse's employer.
- Some entities experienced either higher or lower costs than budgeted for Retirement costs due to greater or lesser participation by employees in the entity's retirement plan than was assumed in the budget. In addition, some entities increased the employer match component of their retirement plans, resulting in higher Retirement Costs than budgeted.
- A number of entities realized lower than budgeted actual costs for Meetings and Travel due to (i) continuing efforts to make greater use of teleconferencing, Webinars and other virtual meeting capabilities rather than in-person meetings; (ii) scheduling meetings at NERC or Regional Entity facilities or the facilities of stakeholders (*e.g.* at the offices of Regional Entity members) rather than in rented, third-party meeting

spaces; or (iii) overall increased corporate attention to controlling travel and meeting costs.

- In particular with respect to Meetings and Travel expense, several entities which moved to new offices with larger meeting spaces, or expanded existing offices, in 2014 or in recent prior years have been able to reduce Meetings and Travel expense by holding more meetings in the entity's office rather than in outside facilities.
- Some entities experienced lower than budgeted Consultants and Contracts expense due to timing delays or deferrals in planned projects.
- Some entities experienced variances in Office Rent or Office Costs due to new or changed office lease terms (including as a result of moving to a new office or taking additional space in the existing office facility), or due to implementing changes in the manner in which the entity accounted for Office Rent or Office Costs, as compared to the terms or accounting reflected in the budget.
- Some entities which moved to new offices or expanded existing offices to accommodate increased staffing, incurred additional costs for capital expenditures (Furniture & Fixtures CapEx, Equipment CapEx, Computer & Software CapEx, and/or Leasehold Improvements) associated with the move to the new office or expansion of the existing office.
- Some actual cost-to-budget variances within program areas are due to the entity budgeting certain costs in one program area but then recording the actual costs in the program area responsible for incurring the cost (*e.g.*, budgeting all outside legal services in Legal and Regulatory but recording actual outside legal expenses in the program area(s) whose activities necessitate the services).
- Some entities budget Professional Services expense for one or two contested compliance hearing per year (*e.g.*, for outside counsel to handle the hearing or for hearing officer services); if no contested hearings occur during the year, an under-budget variance in Professional Services expenses results.
- For some entities, Information Technology projects or Fixed Asset purchases (*e.g.*, office furniture purchases) that were included in the 2014 budget were either (i) completed, or at least initiated, in late 2013, (ii) not carried out in 2014 (*i.e.*, delayed/deferred to 2015), or (iii) initiated later in 2014 than assumed in the budget and therefore not completed in 2014. This resulted in reduced actual IT costs, Capital Expenditures, and/or Consultants and Contracts expense (where the project was to require the use of consulting services or outside contracts compared to the budget). In other cases, projects that were planned and budgeted for execution and completion in 2013 were not fully completed in 2013 or were delayed or deferred into 2014, resulting in unbudgeted or over-budget expenditures in 2014.
- Some entities budgeted certain expenditures as expenses (*e.g.*, as Office Costs), but then determined that the expenditure(s) needed to be capitalized (*i.e.*, recorded as Fixed Asset additions, such as Computer & Software Capital Expenditures or Equipment Capital Expenditures) based on the entity's capitalization policy or capitalization requirements of Generally Accepted Accounting Principles. In other

instances, the reverse occurred. The determination to capitalize rather than expense these expenditures or (vice versa) also impacted actual versus budgeted Depreciation expense.

- Some entities experienced higher or lower Funding from Workshop attendance fees, or other programs conducted for industry participants, due to higher or lower attendance at workshops or other programs than projected in the budget, holding more or fewer Workshops than assumed in the budget, or making a determination not to charge fees (or charging lower fees) for some programs for which fees had been budgeted.

In addition to the above-described causes of actual-to-budget variances, NERC and the Regional Entities experienced other above- or below-budget variances in actual Funding, Expenses and Fixed Asset Additions in individual line items due to particular events and circumstances impacting the particular entity. These variances are identified in the individual actual cost-to-budget comparisons presented in **Attachments 1** through **9**.

NERC and the Regional Entities are taking the actual cost-to-budget comparisons for 2014, as well as year-to-date actual cost-to-budget comparisons for 2015, into account in developing their business plans and budgets for 2016, which are to be submitted to the NERC Board for approval, and then filed with the Commission for approval, in August 2015.

IV. COMPARISON OF ACTUAL COSTS TO BUDGET FOR THE YEAR ENDED DECEMBER 31, 2014 – PEAK RELIABILITY, INC.

Attachment 10 is a comparison of actual costs to budget for 2014 prepared by Peak. Because NERC included Peak's 2014 Business Plan and Budget in NERC's 2014 Business Plan and Budget Filing in Docket No. RR13-9-000, NERC and Peak concluded that an actual cost-to-budget report for Peak for 2014 should be included as part of this filing. Similar to its approach to reviewing Peak's business plans and budgets, NERC has not substantively reviewed and critiqued Peak's 2014 actual cost-to-budget report in the same manner that it reviews the Regional Entities' reports. NERC has, however, reviewed Peak's 2014 actual cost-to-budget report for consistency in presentation and level of detail of information provided with the report

format used by the Regional Entities.

V. METRICS CONCERNING ADMINISTRATIVE COSTS IN 2014 NERC AND REGIONAL ENTITY BUDGETS AND ACTUAL COSTS

In the *June 19, 2008 Budget Compliance Order*, the Commission directed NERC to develop additional metrics analyzing its administrative services expenses and those of the Regional Entities, and to present these metrics in future annual actual cost-to-budget filings and Business Plan and Budget filings. NERC has provided administrative cost metrics for NERC and the Regional Entities and accompanying discussion and analysis in its annual actual cost-to-budget reports for the subsequent years, through 2013. In accordance with the *June 19, 2008 Budget Compliance Order,* the costs incurred by NERC and the Regional Entities in the following functions are and have been considered to be the administrative services costs: Committees and Member Forums, General and Administrative, Legal and Regulatory, Information Technology, Human Resources, and Accounting and Finance.[13]

On February 18, 2015, NERC submitted a filing in Docket No. RR15-6-000 requesting approval to remove or revise certain metrics components in its annual business plan and budget filings and in its annual actual cost-to-budget comparison filings.[14] Specifically with respect to its annual actual cost-to-budget comparison filings, NERC proposed (1) to continue to provide the same metrics data on NERC and Regional Entity administrative services costs and staffing as it has been providing in the annual actual cost-to-budget comparison filings, but (2) to eliminate the narrative discussion of the administrative cost metrics that NERC has previously provided in

[13] *See June 19, 2008 Budget Compliance Order*, footnote 13.

[14] *Request of the North American Electric Reliability Corporation to Revise Certain "Metrics" Filing Components for its Annual Business Plan and Budget Filings and its Annual Actual Cost-to-Budget Trueup Filings*, filed February 18, 2015, in Docket No. RR15-6-000.

the text of the annual actual cost-to-budget comparison filings.[15]

As of the date of this filing, the Commission has not acted on NERC's February 18, 2015 filing. After consulting with Commission Staff, NERC has decided to include in this filing the NERC and Regional Entity administrative services metrics data, as in previous annual filings, but not the narrative discussion of the data, consistent with its filing in Docket No. RR15-6-000. Should the Commission subsequently deny NERC's request in Docket No. RR15-6-000 as it pertains to the annual actual cost-to-budget comparison filings, NERC will promptly submit a revised version of this filing including a narrative discussion of the administrative costs metrics data.[16]

Attachment 11 provides the following three sets of metrics comparisons for NERC and the Regional Entities for their 2014 budgets and 2014 actual costs. In addition, **Attachment 11** provides a comparison of these metrics values for 2012, 2013 and 2014 actual results.

- Statutory indirect expenditures as a percent of total statutory expenditures, and statutory direct expenditures per dollar of statutory indirect expenditures (top row of tables on **Attachment 11**).[17]
- Statutory indirect FTE as a percent of total statutory FTE, and ratio of statutory direct FTE to statutory indirect FTE (middle row of tables on **Attachment 11**).
- Total statutory expenditures per total FTE, statutory direct expenditures per direct FTE, statutory indirect expenditures per indirect FTE, and statutory indirect expenditures per total FTE (bottom row of tables on **Attachment 11**).

These are the same administrative cost metrics that NERC has provided in its previous annual filings comparing actual-to-budget costs for NERC and the Regional Entities for the years 2008 through 2013.

[15] *Id.* at 21-22.

[16] NERC notes that in Docket No. RR15-6-000, no comments were filed with the Commission concerning NERC's request.

[17] The term "expenditures" as used here means expenses plus capital expenditures (fixed asset additions net of depreciation).

VI. CONCLUSION

The North American Electric Reliability Corporation respectfully requests that the Commission accept this filing and Attachments as compliant with the Commission's requirements for annual presentation of comparisons of actual-to-budgeted funding and costs for NERC and the Regional Entities for the year ended December 31, 2014.

Respectfully submitted,

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ATTACHMENT 1

2014 ACTUAL COST-TO-BUDGET COMPARISON

AND

2014 AUDITED FINANCIAL REPORT

FOR

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation 2014 Audited Results – Actual to Budget Variance Analysis

Based upon audited results for the year ending December 31, 2014, NERC was $1.7M, 3.0%, under budget for total expenses and fixed asset (capital) purchases, inclusive of expenses associated with the Cyber Risk Information Sharing Program (CRISP) which were entirely funded by CRISP participants.

2014 ACTUAL VERSUS BUDGET BY CATEGORY, including CRISP

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding, excluding CRISP	53,661,497	53,735,382	(73,885)	
CRISP Third-Party Funding	1,587,876	-	1,587,876	
TOTAL FUNDING	**55,249,373**	**53,735,382**	**1,513,991**	**2.8%**
BUDGET - EXPENSES and FIXED ASSETS				
PERSONNEL EXPENSES	32,730,904	34,059,655	(1,328,751)	-3.9%
MEETINGS, TRAVEL and CONFERENCE CALLS	3,486,929	3,789,525	(302,596)	-8.0%
CONSULTANTS and CONTRACTS	7,857,813	6,828,973	1,028,840	15.1%
RENT	2,737,780	2,617,299	120,481	4.6%
OFFICE COSTS, PROFESSIONAL SERVICES and MISCELLANEOUS	5,916,466	5,832,854	83,612	1.4%
Other Non-Operating Expenses	102,181	144,000	(41,819)	-29.0%
FIXED ASSET PURCHASES (excludes the credit for depreciation)	1,859,327	3,117,790	(1,258,463)	-40.4%
TOTAL BUDGET	**54,691,400**	**56,390,096**	**(1,698,696)**	**-3.0%**
FTEs	**177.3**	**189.5**	**(12.2)**	**-6.4%**

Excluding CRISP, NERC was $3.25M, 5.8%, under budget. The following table and summary of variances by expense category reflect 2014 results excluding funding and expenses related to CRISP. A summary of program activities and expenses related to CRISP are provided on page 6.

2014 ACTUAL VERSUS BUDGET BY CATEGORY, excluding CRISP

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
TOTAL FUNDING	**53,661,497**	**53,735,382**	**(73,885)**	**-0.1%**
BUDGET - EXPENSES and FIXED ASSETS				
PERSONNEL EXPENSES	32,697,006	34,059,655	(1,362,649)	-4.0%
MEETINGS, TRAVEL and CONFERENCE CALLS	3,479,715	3,789,525	(309,810)	-8.2%
CONSULTANTS and CONTRACTS	6,606,569	6,828,973	(222,404)	-3.3%
RENT	2,737,780	2,617,299	120,481	4.6%
OFFICE COSTS, PROFESSIONAL SERVICES and MISCELLANEOUS	5,657,358	5,832,854	(175,496)	-3.0%
Other Non-Operating Expenses	102,181	144,000	(41,819)	-29.0%
FIXED ASSET PURCHASES (excludes the credit for depreciation)	1,859,327	3,117,790	(1,258,463)	-40.4%
TOTAL BUDGET	**53,139,935**	**56,390,096**	**(3,250,161)**	**-5.8%**
FTEs	**177.2**	**189.5**	**(12.2)**	**-6.4%**

As further explained below, NERC was under budget in 2014 primarily due to: (i) lower than budgeted personnel expenses due to staff vacancies and turnover; (ii) lower than budgeted fixed asset expenditures for software application development; (iii) lower than budgeted travel expense due to having fewer FTEs on staff than budgeted; and (iv) lower than budgeted contract and consulting expenses, expenses to support the System Operator Certification and Training programs and consulting support for risk management. These lower than budgeted contract and consulting expenses were offset by higher than budgeted consulting support for the FAC 3 vegetation management project, and higher than budgeted contract expenses for NERCnet and for the secure alerts reporting system.

Following is an explanation of the major factors influencing budgetary performance for 2014, exclusive of expenses associated with CRISP.

- **Funding** - Funding was under budget $73.9k, 0.1%, due primarily to lower than budgeted workshop fees. Although the original budget included fees from attendees of the modeling workshops held by the RAPA program, NERC decided to forego those fees. Additionally, NASPI workshops received funding support from third parties, rather than NERC. Interest was under budget due to extremely low rates of return on invested funds.

- **Personnel Expenses** - $1.4M, 4.0%, under budget
  - Salaries expense, which is comprised of base salaries, incentive compensation, accrued paid time off, employment agency fees, and temporary office services, was $518.8k, 2.0%, under budget, primarily due to having fewer than budgeted FTEs on staff.
    - Base salaries, incentive compensation and accrued paid time off expenses were collectively $686.4k under budget. The company's 2014 personnel expense budget included assumptions regarding timing of new hires and attrition at the time of budget preparation. Management continues to review resource needs and

allocation, as well as assumptions on timing of new hires and attrition, in an effort to minimize significant budget under runs resulting from lower than budgeted FTEs.
        - Temporary office services and employment agency fees were collectively $196.9k over budget due to the increased use of temporary staffing to support NERC's ongoing operations during times of staff vacancies.
    - Payroll taxes were $44.4k, 2.8%, over budget due to a higher maximum taxable earnings cap than the assumption in the budget.
    - Benefits expense, which is comprised of education and training, health and life, workers compensation, and relocation was $337.8, 10.0%, under budget.
        - Health and life benefits were $343.7k, 12.5%, under budget due to having fewer FTEs on staff than budgeted and lower than budgeted renewal costs associated with NERC's health plans.
        - Education and training expenses were $84.1k, 48.1%, over budget due to an increased focus on staff training and professional development.
        - Relocation, workers' compensation and other employee benefits were collectively $78.2k, 17.0%, under budget primarily due to lower than budgeted relocation expenses.
    - Retirement expenses were $550.5k, 19.1%, under budget primarily due to having fewer FTEs on staff, later eligibility dates due to timing of hiring and due to forfeiture of unvested funds related to personnel attrition.

- **Meetings, Travel, Conferencing and Webinar** expenses were collectively under budget $309.8k, 8.2%. Meetings expenses were $59.5k under budget due to third party funding of NASPI workshops as noted above. Travel expenses were $251.1k under budget due to having fewer FTEs on staff and ongoing focus on travel expense management. Conferencing expenses were approximately equal to budget.

- **Consultants and Contracts** expenses were $222.4k, 3.3% under budget. The following table summarizes the over and under budget variances for Consultants and Contracts by Program area.

CONSULTANTS and CONTRACTS	2014 Actual	2014 Budget	Over(Under)
COMPLIANCE OPERATIONS	432,286	400,000	32,286
RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS	800,887	638,085	162,802
SITUATION AWARENESS	1,716,750	1,289,108	427,642
CRITICAL INFRASTRUCTURE DEPARTMENT	176,955	190,000	(13,045)
ES-ISAC	516,819	786,450	(269,631)
TRAINING, EDUCATION and OPERATOR CERTIFICATION	417,509	848,830	(431,322)
GENERAL and ADMINISTRATIVE	17,955	-	17,955
POLICY and EXTERNAL AFFAIRS	13,900	75,000	(61,100)
INFORMATION TECHNOLOGY	2,017,016	1,944,000	73,016
HUMAN RESOURCES	298,365	257,500	40,865
FINANCE and ACCOUNTING	198,127	400,000	(201,873)
CONTRACTS and CONSULTANTS (excluding CRISP)	**6,606,569**	**6,828,973**	**(222,404)**

- Compliance Operations – Over budget $32.3k for outside consulting support in connection with the Reliability Assurance Initiative pilot programs and development of the associated internal control evaluation and testing processes.
- Reliability Assessments and Performance Analysis – Over budget $162.8k due to the FAC 3 vegetation management project which was anticipated to be funded from operating reserves in the 2014 Business Plan and Budget.
- Situation Awareness – $427.6k over budget due to higher than budgeted expenses for NERCnet and for the secure alerts reporting system, offset by lower than budgeted expenses for SAFNR.
- Critical Infrastructure Department – Under budget $13.0k due to lower than budgeted expenses to support the ESCC Committee.
- ES-ISAC – Under budget $269.6k due to lower than budgeted expenses related to cyber risk preparedness assessments, communications and software support services.
- Training, Education and Operator Certification –$431.3k under budget due to: (i) lower than budgeted expenses related to the system operator database improvement project and examination development project; (ii) lower than budgeted system operator testing expenses resulting from a new vendor contract signed after the 2014 budget was developed; and (iii) lower than budgeted costs for industry and staff training.
- General and Administrative - $18.0k over budget due to costs associated with the ERO effectiveness survey.
- Policy and External Affairs – Under budget $61.1k due to a reduction in the need for outside consulting to support external affairs as a result of certain duties now being performed internally.
- Information Technology – $73.0k over budget primarily due to slightly higher than budgeted total software development costs.
- Human Resources - $40.8k over budget due to vendor support for benefits enrollment process improvements.
- Finance and Accounting - $201.9k under budget due to lower than budgeted consulting support.

- **Rent** - $120.5k, 4.6%, over budget due to: (i) a reduction in sublease revenue from NERC's former Washington, DC office in connection with negotiation and execution of a sublease amendment as a result of the subtenant's bankruptcy reorganization; and (ii) an increase in property taxes in Atlanta based on an updated assessment by Fulton County. With respect to the sublease agreement, the company received an upfront payment in connection with the execution of its current lease space in Washington, D.C. to offset potential liabilities associated with the sublease. This upfront payment is included in the company's working capital reserves and is being amortized over the term of the lease and is sufficient to offset the reduction in sublease revenue resulting from the subtenant bankruptcy.

- **Office Costs, Professional Services and Miscellaneous** - $175.5k,3.0%, under budget
  - Office Costs were $237.3k, 6.8%, under budget due primarily to lower than budgeted expenses for telecommunications, equipment service agreements, and software licenses.
  - Professional Services were $78.5k, 3.4%, over budget due to: (i) slightly higher than budgeted Trustee retainer and search fees as further detailed below; (ii) higher than budgeted outside legal expenses ; and (iii) fees related to the design and implementation of an executive supplemental retirement plan.
  - Miscellaneous expenses, which includes employee rewards and recognition expenses and costs associated with community responsibility activities were $16.6k, 45.6%, under budget.

- **Depreciation Expense** was under budget due to completion of fewer ERO Enterprise software application projects than expected. The variances in depreciation are not explained in the following summaries by program because the expense has no impact on the budget or assessments.

- **Other Non-Operating Expenses** were $41.8k, 29.0%, under budget due to lower than budgeted interest expense associated with the company's capital financing program. Interest expense is lower than budget due to a lower than budgeted interest rate and a delay in closing the capital financing program loan. The loan closed in January, 2014 instead of the fourth quarter of 2013 as originally planned. Under the loan agreements, NERC pays a variable rate based on certain indices and the rate at closing was 2.9% compared to the 2014 budgeted rate of 3.5%.

- **Fixed Asset Purchases**, excluding depreciation, were $1.3M, 40.4%, under budget primarily due to a reduction in software development and associated hardware expenditures as NERC updated and refined the ERO Enterprise and internal software application development strategies.

Board of Trustees Expenses

As detailed in the following table, Board of Trustee expenses were over budget $11.0k, 0.7%, in 2014. The increase in trustee compensation was approved by the Board on August 15, 2013.

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Board of Trustee Expenses				
Meetings and Travel Expenses				
Quarterly Board Meetings and Conference Calls	226,408	256,206	(29,798)	-11.6%
Trustee Travel	168,207	155,000	13,207	8.5%
Total Board of Trustees Meetings and Travel Expenses	**394,615**	**411,206**	**(16,591)**	**-4.0%**
Professional Services				
Independent Trustee Fees	1,010,000	1,000,000	10,000	1.0%
Trustee Search Fees	87,563	70,000	17,563	25.1%
Total Board of Trustee Professional Services Expenses	**1,097,563**	**1,070,000**	**27,563**	**2.6%**
Total Board of Trustee Expenses	**1,492,178**	**1,481,206**	**10,972**	**0.7%**

CRISP

NERC's role as program manager for CRISP was budgeted to begin in 2015, and therefore no funding or expenses for CRISP were included in NERC's 2014 budget. During the fourth quarter of 2014, contracts between NERC and Pacific Northwest National Laboratory (PNNL) and between NERC and participating utilities were finalized and the project began ahead of the planned January 1, 2015 start date. As previously noted, all expenses incurred in 2014 were fully funded by CRISP participants. Pursuant to the master agreement with CRISP utility participants funding is provided in advance. The impact of these pre-payments from an accounting perspective is that the funds are recorded in full as assets on the company's balance sheet, offset by deferred liabilities and are only recognized as revenues on the Statement of Activities as expenses are incurred. CRISP funds are segregated from other statutory funds and are utilized solely to support CRISP. After management review of the monthly variance report, CRISP funds are transferred to NERC's general operating account to offset the actual expenses incurred. With respect to 2014 CRISP expenses, 2014 funding in excess of expenses was tracked and applied as a credit against 2015 CRISP funding requirements[1]. In addition, the premiums for cyber and professional liability insurance policy which was required to be put in place pursuant to the CRISP master agreement were paid in advance but are recorded on the Statement of Activities in equal monthly amounts over the 12 month term of the policy. The prepaid portion of the insurance policy is included in CRISP operating reserves. The personnel costs for ES-ISAC personnel working on CRISP during the month are allocated based upon

[1] NERC issued credits for $1.5M in funding received in excess of 2014 expenses.

the ratio of the time recorded in the month to the time spent on the CRISP activity code by each employee to the total time recorded by such employee during the month.

CRISP expenses recorded in 2014 were approximately $1.6M. Funding for the $500k special insurance reserve fund established pursuant to the terms of the CRISP master agreement is accounted for on the Statement of Financial Position as a long-term liability, and is restricted from use. All 2014 CRISP expenses were fully funded by the participants in the program.

Allocation of Indirect Expenses and Fixed Assets by Program

Total expenses and fixed asset expenditures, net of depreciation for all administrative programs were $92.7k, 0.4% under budget. Total expenses of the administrative programs were $25.4M, which was $919.7k, 3.8% over budget. Direct expenses were over budget primarily due to higher personnel expenses as a result of having more administrative personnel than budgeted due to reallocation of resources to administrative program functions supporting all operating areas. The actual and budgeted allocations of indirect expenses by FTE were $228.5k and $188.0k, respectively, for an increase of $30.5k per FTE.

Total fixed assets, net of depreciation for the administrative programs were ($105.1k), which was $872.0k, 114.6%, under budget. Total fixed assets were under budget primarily due to lower than budgeted purchases of capitalized computers and software in the Information Technology department as explained in more detail in the variance report for Information Technology that follows beginning on page 31. The actual and budgeted allocations of fixed assets net of depreciation by FTE were ($0.9k) and $5.5k, respectively for a decrease of $6.4k per FTE.

The variances in indirect expenses and the allocation of fixed assets reflected in the variance reports by department are the result of the change in costs per FTE and the difference in actual versus budgeted FTE by department.

Use of Statutory Funds for Non-Statutory Activities

NERC does not have non-statutory activities and therefore did not use statutory funds for non-statutory activities.

Operating Reserve Analysis

As of December 31, 2014, the total balance in working capital and operating reserves was $7.46M. The balances in the Future Obligations Reserve, Known Contingency Reserve, Unknown Contingency Reserve, the System Operator Reserves, and CRISP Reserves as of December 31, 2014, were $3.6M, $850.0k, $1.2M, $1.3M, and $585.5k respectively. The balance in working capital and operating reserves as of December 31, 2014 was approximately $1.9M higher than budget, inclusive of CRISP reserves which were not budgeted and are entirely funded by CRISP participants.

A total of $711.0k of Unknown Contingency Reserves were used in 2014: (i) $50.5k for RAI contract support to develop the internal control evaluation and testing processes; (ii) $50.4k for data modeling and change orders related to generation databases; (iii) $25.1k for preliminary work on the development of a replacement for a software application used in connection with the Generator Analysis Database (GADS); (iv) $32.4k to begin preparations for GridEx III in 2015; (v) $43.6k for staff development and HR administrative support; (vi) $18.0k for an ERO effectiveness survey; and (vii) $491.1k for IT consultants, compliance database maintenance, and various IT infrastructure projects, including disaster recovery and network simplification. $150k of Known Contingency Reserves was used for the FAC3 vegetation research project. All uses of reserves received the appropriate approvals pursuant to NERC's Working Capital and Operating Reserve Policy.

OPERATING RESERVE ANALYSIS - as of December 31, 2014

				December 31, 2014 Reserve Balances				
	2014 Actual	2014 Budget*	Variance - Actual to Budget	Future Obligations Reserve	Known Contingency Reserves	Unknown Contingency Reserves	System Operator Reserves	CRISP Reserves***
Beginning Balance Operating Reserves - 1/1/14	**6,264,672**	**8,217,862**	**(1,953,190)**	**3,817,478**	**1,000,000**	**(69,672)**	**1,516,866**	**-**
Proceeds from Financing Activities (non-current portion only)	456,806		456,806			456,806		
Change in Reserves from Current Year Operations								
Generation (Use) from Budgeted Operations	1,418,982	(2,654,714)	3,996,172			1,641,335	(222,353)	-
Generation (Use) from Reserves	(861,009)	-	(783,485)		(150,000)	(711,009)		
Other adjustments to reserves**	181,456		181,456	(247,986)		(156,058)		585,500
Reserve Balance	**7,460,907**	**5,563,148**	**1,897,759**	**3,569,492**	**850,000**	**1,161,402**	**1,294,513**	**585,500**

*The 2014 budget included a $1.2M reduction in Known and Unknown reserves and a $438.3k planned reduction in the System Operator Reserves, for a total budgeted reduction in reserves of $1,660,724.

**Represents transactions recorded only on the Statement of Financial Position (balance sheet) and do not impact the Statement of Activities (income statement), including recording of capitalized leases, amortization of long-term lease obligations and establishing CRISP insurance reserve

***Actual funding received from CRISP participants in excess of year-to-date actual expenses, pre-paid insurance and the insurance reserve fund as of December 31, 2014 was $2.4M. This amount is not reflected in the CRISP Reserve balance because the funds will be used for future expenses or credited back to the participants.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Statement of Activities and Fixed Assets
(Audited)
For the period ended 12/31/2014

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	51,401,382	51,401,382	-	
Penalties	290,000	290,000	-	
Third-Party Funding (CRISP)	1,587,876	-	1,587,876	
Testing	1,659,137	1,620,000	39,137	
Services & Software	77,000	50,000	27,000	
Workshop Fees	231,090	354,000	(122,910)	
Interest	2,830	20,000	(17,170)	
Miscellaneous	58	-	58	
Total Funding	55,249,373	53,735,382	1,513,991	2.8%
Expenses				
Personnel Expenses				
Salaries	25,729,089	26,218,572	(489,483)	
Payroll Taxes	1,615,713	1,570,954	44,759	
Employee Benefits	3,049,721	3,385,917	(336,196)	
Savings & Retirement	2,336,381	2,884,212	(547,831)	
Total Personnel Expenses	32,730,904	34,059,655	(1,328,751)	-3.9%
Meeting Expenses				
Meetings	992,687	1,052,150	(59,463)	
Travel	2,175,616	2,419,525	(243,909)	
Conference Calls	318,627	317,850	777	
Total Meeting Expenses	3,486,929	3,789,525	(302,596)	-8.0%
Operating Expenses				
Consultants and Contracts	7,857,813	6,828,973	1,028,840	
Rent & Improvements	2,737,780	2,617,299	120,481	
Office Costs	3,268,753	3,506,074	(237,321)	
Professional Services	2,627,851	2,290,280	337,571	
Miscellaneous	19,862	36,500	(16,638)	
Depreciation	1,845,951	2,333,007	(487,056)	
Total Operating Expenses	18,358,010	17,612,133	745,877	4.2%
Other Non-Operating Expenses	102,181	144,000	(41,819)	-29.0%
Indirect Expenses	-	-	-	-
Total Expenses	54,678,024	55,605,313	(927,289)	-1.7%
Net Change in Assets	**571,349**	**(1,869,931)**	**2,441,280**	**-130.6%**
Fixed Assets				
Depreciation	(1,845,951)	(2,333,007)	487,056	
Computer & Software	1,470,558	2,904,790	(1,434,232)	
Furniture & Fixtures	-	-	-	
Equipment	352,392	213,000	139,392	
Leasehold Improvements	36,377	-	36,377	
Allocation of Fixed Assets	-	-	-	
Incr(Dec) in Fixed Assets	**13,376**	**784,783**	**(771,407)**	**-98.3%**
Total Budget (Expenses plus Incr(Dec) in Fixed Assets)	**54,691,400**	**56,390,095**	**(1,698,695)**	**-3.0%**
FTE's	**177.31**	**189.53**	**(12.22)**	**-6.4%**

Reliability Standards

Statement of Activities and Fixed Asset Budget

RELIABILITY STANDARDS	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	10,000,443	10,000,443	-	-
Penalties	58,951	58,951	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	96,900	104,000	(7,100)	-6.8%
Interest	563	3,976	(3,413)	-85.8%
Misc.	-	-	-	-
Total Funding	10,156,857	10,167,370	(10,513)	-0.1%
Expenses				
Personnel Expenses				
Salaries	2,731,348	3,308,688	(577,340)	-17.4%
Payroll Taxes	198,553	210,130	(11,577)	-5.5%
Employee Benefits	411,701	454,850	(43,149)	-9.5%
Savings & Retirement	307,149	377,588	(70,439)	-18.7%
Total Personnel Expenses	3,648,751	4,351,256	(702,505)	-16.1%
Meeting Expenses				
Meetings	229,787	185,000	44,787	24.2%
Travel	348,069	400,000	(51,931)	-13.0%
Conference Calls	133,713	123,748	9,965	8.1%
Total Meeting Expenses	711,569	708,748	2,821	0.4%
Operating Expenses				
Consultants and Contracts	-	-	-	-
Rent & Improvements	-	-	-	-
Office Costs	70,958	90,350	(19,392)	-21.5%
Professional Services	-	-	-	-
Miscellaneous	714	500	214	42.9%
Depreciation	3,273	-	3,273	-
Total Operating Expenses	74,945	90,850	(15,905)	-17.5%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	5,013,513	4,872,999	140,514	2.9%
Total Expenses	9,448,778	10,023,853	(575,075)	-5.7%
Net Change in Assets	708,078	143,517	564,561	393.4%
Fixed Assets				
Depreciation	(3,273)	-	(3,273)	-
Computer & Software	379,682	-	379,682	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	(20,709)	143,517	(164,226)	-114.4%
Incr(Dec) in Fixed Assets	355,700	143,517	212,183	147.8%
Total Budget	9,804,478	10,167,370	(362,892)	-3.6%
FTE's	21.94	25.92	(3.98)	-15.4%

Explanation of Variances by Category – Reliability Standards

- **Personnel** – Salaries, payroll taxes, benefits and retirement costs were collectively under budget $702.5k, 16.1%, due to having 3.98, 15.4%, fewer FTEs on staff than budgeted. In addition to having fewer FTEs on staff than budgeted, personnel expenses were also impacted by the following:
    - Payroll Taxes – The under budget variance due to having fewer FTEs on staff than budgeted was partially offset by higher than budgeted FICA taxes due to a higher maximum salary subject to the tax than was assumed in the budget.
    - Benefits - The under budget variance due to having fewer FTEs on staff than budgeted was partially offset by higher than budgeted training and education expenses.
- **Meetings, Travel and Conferencing Expenses –** Collectively over budget $2.8k, 0.4%.
    - Meetings – Over budget due to CIP v5 meetings, participation in an Electric Infrastructure Security Council meeting, and a physical security technical conference which were not budgeted.
    - Travel – Under budget due to having fewer FTEs on staff than budgeted and management focus on travel expense management.
    - Conferencing Expenses - $10.0k, 8.1%, over budget due to an increase in the number of webinars related to CIP v5 and development of the physical security standard.
- **Office Costs** – Under budget $19.4k, 21.5%, due to lower than budgeted telecommunications expenses as a result of having fewer FTEs on staff than budgeted and due to lower telecommunications costs for NERC in total as explained above.

Compliance Operations, Investigations and Organization Registration and Certification

Statement of Activities and Fixed Asset Budget

COMPLIANCE OPERATIONS, INVESTIGATIONS and ORGANIZATION REGISTRATION and CERTIFICATION	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	9,400,511	9,400,511	-	0.0%
Penalties	52,401	52,401	-	0.0%
Third-Party Funding (CRISP)				
Testing				
Services & Software				
Workshop Fees	0	40,000	(40,000)	-100.0%
Interest	500	3,534	(3,034)	-85.8%
Miscellaneous				
Total Funding	9,453,412	9,496,446	(43,034)	-0.5%
Expenses				
Personnel Expenses				
Salaries	3,184,927	3,192,809	(7,882)	-0.2%
Payroll Taxes	194,357	202,068	(7,711)	-3.8%
Employee Benefits	385,195	404,311	(19,116)	-4.7%
Savings & Retirement	305,942	364,901	(58,959)	-16.2%
Total Personnel Expenses	4,070,421	4,164,089	(93,668)	-2.2%
Meeting Expenses				
Meetings	61,290	70,000	(8,710)	-12.4%
Travel	366,137	312,657	53,480	17.1%
Conference Calls	22,271	16,574	5,697	34.4%
Total Meeting Expenses	449,698	399,231	50,467	12.6%
Operating Expenses				
Consultants and Contracts	432,286	400,000	32,286	8.1%
Rent & Improvements	0	0	0	
Office Costs	54,701	73,500	(18,799)	-25.6%
Professional Services	0	0	0	
Miscellaneous	0	500	(500)	-100.0%
Depreciation	4,668	0	4,668	
Total Operating Expenses	491,655	474,000	17,655	3.7%
Other Non-Operating Expenses	-	-	-	
Indirect Expenses	4,992,947	4,331,555	661,392	15.3%
Total Expenses	10,004,720	9,368,875	635,846	6.8%
Net Change in Assets	(551,308)	127,571	(678,880)	-532.2%
Fixed Assets				
Depreciation	(4,668)	-	(4,668)	
Computer & Software	-	-	-	
Furniture & Fixtures	-	-	-	
Equipment	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	(20,624)	127,570	(148,195)	
Incr(Dec) in Fixed Assets	(25,292)	127,570	(152,863)	-119.8%
Total Budget	9,979,428	9,496,446	482,983	5.1%
FTE's on 12/31/14 - per Original Budget	21.85	23.04	(1.19)	-5.2%

Explanation of Variances by Category – Compliance Operations, Investigations and Organization Registration and Certification

- **Funding** – Under budget $43.0k, 0.5%, primarily because the auditor workshops were held in the NERC offices rather than hotels to reduce costs and as a result, workshop fees were not collected from attendees.
- **Personnel** – Salaries, payroll taxes, benefits and retirement costs were collectively under budget $93.7k, 2.2%. Actual FTEs were 1.2 under budget, 5.2%. In addition to having fewer FTEs on staff than budgeted, retirement expenses were also under budget due to timing of hiring which impacts eligibility in the retirement plan.
- **Meetings, Travel and Conferencing Expenses**
    - Meeting expenses, which are the cost of hotel, catering and audio visual expenses were $8.7k, 12.4% under budget due utilization of the NERC offices for auditors workshops instead of hotels as planned in the budget.
    - Travel was $53.5k, 17.1% over budget due to increased travel related to the Reliability Assurance Initiative (RAI) implementation.
    - Conferencing expenses were $5.7k, 34.4% over budget related to RAI implementation.
- **Operating Expenses**
    - Consultant and contract expenses were $32.3k, 8.1% over budget for outside consulting support in connection with the RAI pilot programs and development of the associated internal control evaluation and testing processes.
    - Office costs were$18.8k, 25.6% under budget due to lower than budgeted telecommunications expenses for NERC in total as explained above.

Compliance Enforcement

Statement of Activities and Fixed Asset Budget

COMPLIANCE ENFORCEMENT	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	6,350,810	6,350,810	-	-
Penalties	41,484	41,484	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	-	-	-	-
Interest	396	2,798	(2,402)	-85.8%
Miscellaneous	-	-	-	-
Total Funding	6,392,690	6,395,092	(2,402)	-
Expenses				
Personnel Expenses				
Salaries	1,773,005	2,043,427	(270,422)	-13.2%
Payroll Taxes	120,592	132,855	(12,263)	-9.2%
Employee Benefits	192,416	320,080	(127,664)	-39.9%
Savings & Retirement	171,172	234,210	(63,038)	-26.9%
Total Personnel Expenses	2,257,185	2,730,572	(473,387)	-17.3%
Meeting Expenses				
Meetings	1,492	2,500	(1,008)	-40.3%
Travel	60,171	85,298	(25,127)	-29.5%
Conference Calls	1,109	5,081	(3,972)	-78.2%
Total Meeting Expenses	62,773	92,879	(30,106)	-32.4%
Operating Expenses				
Consultants and Contracts	-	-	-	-
Rent & Improvements	-	-	-	-
Office Costs	23,731	41,000	(17,269)	-42.1%
Professional Services	-	-	-	-
Miscellaneous	759	500	259	51.7%
Depreciation	2,846	-	2,846	-
Total Operating Expenses	27,336	41,500	(14,164)	-34.1%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	3,089,457	3,429,147	(339,690)	-9.9%
Total Expenses	5,436,751	6,294,098	(857,347)	-13.6%
Net Change in Assets	955,939	100,994	854,945	846.5%
Fixed Assets				
Depreciation	(2,846)	-	(2,846)	-
Computer & Software	-	-	-	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	(12,761)	100,993	(113,755)	-112.6%
Incr(Dec) in Fixed Assets	(15,608)	100,993	(116,601)	-115.5%
Total Budget	5,421,144	6,395,092	(973,948)	-15.2%
FTE's	13.52	18.24	(4.72)	-25.9%

Explanation of Variances by Category – Compliance Enforcement

- **Personnel** – Personnel expenses were $473.4k, 17.3%, under budget due to having 4.7, 25.9%, fewer FTEs on staff than budgeted. The remaining under budget variance in FTEs was due to open positions during the year. In addition to having fewer FTEs on staff than budgeted, personnel expenses were also impacted by the following:
    - Payroll Taxes – The under budget variance due to having fewer FTEs on staff than budgeted was partially offset by higher than budgeted FICA taxes due to a higher maximum salary subject to the tax than was assumed in the budget.
    - Benefits – Also under budget because no relocation expense was incurred during the year.
- **Meetings, Travel and Conferencing Expenses –** Collectively under budget $30.1k, 32.4%, due to lower than budgeted travel expenses as a result of having fewer FTEs on staff and in response to ongoing focus on travel expense management.
- **Office Costs –** Under budget $17.3k, 42.1%, due to lower telecommunications expense as a result of having fewer FTEs on staff than budgeted and due to lower than budgeted telecommunications expenses for NERC in total as explained above.

Reliability Assessments and Performance Analysis

Statement of Activities and Fixed Asset Budget

RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	8,214,496	8,214,496	-	-
Penalties	43,190	43,190	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	77,000	50,000	27,000	54.0%
Workshop Fees		40,000	(40,000)	-100.0%
Interest	412	2,913	(2,501)	-85.8%
Miscellaneous	-	-	-	-
Total Funding	8,335,098	8,350,599	(15,501)	-0.2%
Expenses				
Personnel Expenses				
Salaries	2,817,484	2,604,056	213,428	8.2%
Payroll Taxes	182,439	159,156	23,283	14.6%
Employee Benefits	321,377	333,241	(11,864)	-3.6%
Savings & Retirement	272,215	294,179	(21,964)	-7.5%
Total Personnel Expenses	3,593,515	3,390,632	202,883	6.0%
Meeting Expenses				
Meetings	98,143	90,000	8,143	9.0%
Travel	335,114	385,000	(49,886)	-13.0%
Conference Calls	26,300	31,950	(5,650)	-17.7%
Total Meeting Expenses	459,557	506,950	(47,393)	-9.3%
Operating Expenses				
Consultants and Contracts	800,887	638,085	162,802	25.5%
Rent & Improvements	-	-	-	-
Office Costs	136,731	139,135	(2,404)	-1.7%
Professional Services	-	-	-	-
Miscellaneous	118	500	(382)	-76.4%
Depreciation	298,743	228,000	70,743	31.0%
Total Operating Expenses	1,236,479	1,005,720	230,759	22.9%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	4,275,425	3,570,149	705,276	19.8%
Total Expenses	9,564,976	8,473,451	1,091,525	12.9%
Net Change in Assets	(1,229,877)	(122,852)	(1,107,026)	901.1%
Fixed Assets				
Depreciation	(298,743)	(228,000)	(70,743)	31.0%
Computer & Software	47,206	-	47,206	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	(17,660)	105,146	(122,806)	-116.8%
Incr(Dec) in Fixed Assets	(269,197)	(122,854)	(146,343)	119.1%
Total Budget	9,295,779	8,350,597	945,183	11.32%
FTE's	18.71	18.99	(0.28)	-1.5%

Explanation of Variances by Category – Reliability Assessments and Performance Analysis (RAPA)

- **Funding**
  - Fees collected for services and software were $27.0k, 54.0%, higher than budgeted due to increased requests from industry for historical data related to generation availability.
  - Workshop fees were not collected from attendees of the modeling workshops because the workshops were held in the NERC and Regional Entity offices, resulting in funding being $40.0k under budget.
- **Personnel –**
  - Salaries expense was over budget due to increased use of temporary office services to support ongoing initiatives during periods of staff vacancies and due to the reallocation of budgeted FTEs to support RAPA resource needs, which resulted in higher than budgeted average salary and incentive compensation per FTE.
  - Payroll taxes were over budget due to a higher maximum taxable earnings cap than the assumption in the budget.
  - Benefits were under budget due to lower than budgeted renewal costs associated with NERC's health plans.
  - Retirement costs were under budget due to timing of hiring which impacts eligibility in the retirement plan.
- **Meetings, Travel and Conferencing Expenses** were collectively $47.4k, 9.3%, under budget due primarily to lower travel in response to ongoing focus on travel expense management.
- **Operating Expenses**
  - **Contract and Consultant** expenses were over budget $162.8k due to the FAC 3 vegetation management project as explained above.
- **Fixed Assets –** The over budget variance of $47.2k for computer and software capex is related to initiation of the development of a Reliability Assessment Data System (RADS), which was budgeted in Information Technology as part of the total budget for ERO Enterprise software application development. Actual costs are charged to RAPA to match expenditures with the statutory program served.

Situation Awareness

Statement of Activities and Fixed Asset Budget

SITUATION AWARENESS	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	4,493,115	4,493,115	-	-
Penalties	14,192	14,192	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	-	75,000	(75,000)	-100.0%
Interest	135	957	(822)	-85.8%
Miscellaneous	-	-	-	-
Total Funding	4,507,442	4,583,264	(75,822)	-1.7%
Expenses				
Personnel Expenses				
Salaries	780,206	915,216	(135,010)	-14.8%
Payroll Taxes	53,969	60,207	(6,238)	-10.4%
Employee Benefits	127,621	109,501	18,120	16.5%
Savings & Retirement	75,193	104,293	(29,100)	-27.9%
Total Personnel Expenses	1,036,989	1,189,217	(152,227)	-12.8%
Meeting Expenses				
Meetings	5,900	171,000	(165,100)	-96.5%
Travel	37,482	28,020	9,462	33.8%
Conference Calls	748	4,000	(3,252)	-81.3%
Total Meeting Expenses	44,130	203,020	(158,890)	-78.3%
Operating Expenses				
Consultants and Contracts	1,716,750	1,289,108	427,642	33.2%
Rent & Improvements	-	-	-	-
Office Costs	41,289	47,750	(6,461)	-13.5%
Professional Services	-	-	-	-
Miscellaneous	-	500	(500)	-100.0%
Depreciation	718	161,498	(160,780)	-99.6%
Total Operating Expenses	1,758,758	1,498,856	259,902	17.3%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	1,368,776	1,173,129	195,646	16.7%
Total Expenses	4,208,652	4,064,222	144,431	3.6%
Net Change in Assets	298,790	519,042	(220,253)	-42.4%
Fixed Assets				
Depreciation	(718)	(161,498)	160,780	-99.6%
Computer & Software	-	645,990	(645,990)	-100.0%
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	(5,654)	34,550	(40,204)	-116.4%
Incr(Dec) in Fixed Assets	(6,372)	519,042	(525,415)	-101.2%
Total Budget	4,202,280	4,583,264	(380,983)	-8.3%
FTE's	5.99	6.24	(0.25)	-4.0%

Explanation of Variances by Category – Situation Awareness

- **Funding -** NASPI workshops were entirely funded by third parties in 2014, in which reduced NERC funding of $75.0k. When the 2014 budget was developed, it was assumed that NERC might continue to sponsor NASPI workshops.
- **Personnel –** Collectively under budget for salaries, payroll taxes, employee benefits and retirement expenses $152.2k, 12.8%. FTEs were 0.25, 4.0%, under budget.
    - Salaries expense was under budget due to lower average salary per employee than budgeted.
    - Payroll taxes were lower than budgeted due to lower average salaries, offset by the higher maximum taxable earnings cap than the assumption in the budget.
    - Benefits were over budget due to higher than budgeted education and benefit expenses.
    - Retirement costs were under budget due to timing of hiring which impacts eligibility in the retirement plan.
- **Meetings, Travel and Conferencing Expenses –** Collectively $158.9k, 78.3%, under budget primarily due to lower than budgeted meeting expense. In addition, a portion of the quarterly meetings of the Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee, were budgeted in Situation Awareness but actual costs were charged to the departments with the personnel and activities supporting these committees.
- **Operating Expenses**
    - Consultant and Contract expenses were $427.6k, 33.2%, over budget due to: (i) higher than budgeted expenses for NERCnet; and (ii) higher than budget expenses for the secure alerts reporting system due to delays in a previously scheduled replacement system, as noted below. These higher than budgeted expenses were offset by lower than budgeted expenses for SAFNR.
- **Fixed Assets**
    - The planned development of a new secure alerts system was deferred pending further review of alternative systems and as a result, there were no expenditures for computer and software fixed assets.

Event Analysis

Statement of Activities and Fixed Asset Budget

EVENT ANALYSIS	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	3,975,065	3,975,065	-	-
Penalties	21,834	21,834	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	48,634	50,000	(1,366)	-2.7%
Interest	208	1,473	(1,265)	-85.8%
Miscellaneous	-	-	-	-
Total Funding	4,045,741	4,048,372	(2,631)	-0.1%
Expenses				
Personnel Expenses				
Salaries	1,339,543	1,470,290	(130,747)	-8.9%
Payroll Taxes	86,998	91,480	(4,482)	-4.9%
Employee Benefits	135,138	168,463	(33,325)	-19.8%
Savings & Retirement	162,695	167,286	(4,591)	-2.7%
Total Personnel Expenses	1,724,373	1,897,519	(173,146)	-9.1%
Meeting Expenses				
Meetings	84,732	67,000	17,732	26.5%
Travel	124,181	155,000	(30,819)	-19.9%
Conference Calls	14,202	31,864	(17,662)	-55.4%
Total Meeting Expenses	223,115	253,864	(30,749)	-12.1%
Operating Expenses				
Consultants and Contracts	-	-	-	-
Rent & Improvements	-	-	-	-
Office Costs	28,261	38,519	(10,258)	-26.6%
Professional Services	-	-	-	-
Miscellaneous	-	500	(500)	-100.0%
Depreciation	704	193,667	(192,963)	-99.6%
Total Operating Expenses	28,965	232,686	(203,721)	-87.6%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	1,962,902	1,804,815	158,087	8.8%
Total Expenses	3,939,356	4,188,884	(249,528)	-6.0%
Net Change in Assets	106,385	(140,512)	246,898	-175.7%
Fixed Assets				
Depreciation	(704)	(193,667)	192,963	-99.6%
Computer & Software	8,828	-	8,828	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	(8,108)	53,154	(61,262)	-115.3%
Incr(Dec) in Fixed Assets	15	(140,513)	140,528	-100.0%
Total Budget	3,939,371	4,048,372	(109,001)	-2.69%
FTE's	8.59	9.60	(1.01)	-10.5%

Explanation of Variances by Category – Event Analysis

- **Personnel -** Collectively under budget for salaries, payroll taxes, employee benefits and retirement expenses $173.1k, 9.1%, primarily due to having 1.0, 10.5%, fewer FTEs on staff than budgeted. In addition to having fewer FTEs on staff than budgeted, personnel expenses were also impacted by the following:
    - Payroll Taxes – The under budget variance due to having fewer FTEs on staff than budgeted was partially offset by higher than budgeted FICA taxes due to a higher maximum salary subject to the tax than was assumed in the budget.
    - Benefits – There were no relocation expenses in this program in 2014 and due to lower than budgeted renewal costs associated with NERC's health plans.
- **Meetings, Travel and Conferencing Expenses**
    - Meeting expenses were $17.7, 26.5%, over budget due to partial allocation of costs associated with the quarterly OC-PC-CIPC meetings that were budgeted in Situation Awareness, as previously noted.
    - Travel expense was $30.8k, 19.9%, under budget due to having fewer FTEs on staff and management focus on travel expense management.
    - Conferencing expenses were $17.7k, 55.4%, under budget due to no major events that required use of the service.
- **Operating Expenses**
    - Office costs were $10.3k, 26.6%, under budget due to lower telecommunications expense as a result of having fewer FTEs on staff and lower than budgeted telecommunications expenses for NERC in total as explained above.
- **Fixed Assets –** The $8.8k in computer and software is related to beginning development of an event analysis software application that was budgeted in IT.

Critical Infrastructure Department and ES-ISAC

Statement of Activities and Fixed Asset Budget

CRITICAL INFRASTRUCTURE DEPARTMENT and ES-ISAC	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	9,517,444	9,517,444	-	-
Penalties	45,941	45,941	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	85,556	45,000	40,556	90.1%
Interest	438	3,098	(2,660)	-85.8%
Miscellaneous	-	-	-	-
Total Funding	9,649,379	9,611,484	37,896	0.4%
Expenses				
Personnel Expenses				
Salaries	2,304,541	3,220,485	(915,944)	-28.4%
Payroll Taxes	157,018	191,249	(34,231)	-17.9%
Employee Benefits	251,599	354,474	(102,875)	-29.0%
Savings & Retirement	253,742	366,599	(112,857)	-30.8%
Total Personnel Expenses	2,966,901	4,132,806	(1,165,906)	-28.2%
Meeting Expenses				
Meetings	177,948	145,000	32,948	22.7%
Travel	256,744	328,428	(71,684)	-21.8%
Conference Calls	22,094	32,574	(10,480)	-32.2%
Total Meeting Expenses	456,786	506,002	(49,216)	-9.7%
Operating Expenses				
Consultants and Contracts	693,774	976,450	(282,676)	-28.9%
Rent & Improvements	-	-	-	-
Office Costs	97,802	86,250	11,552	13.4%
Professional Services	-	-	-	-
Miscellaneous	210	500	(290)	-58.0%
Depreciation	16,580	-	16,580	-
Total Operating Expenses	808,366	1,063,200	(254,834)	-24.0%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	3,178,576	3,797,630	(619,054)	-16.3%
Total Expenses	7,410,629	9,499,638	(2,089,010)	-22.0%
Net Change in Assets	2,238,750	111,846	2,126,907	1901.6%
Fixed Assets				
Depreciation	(16,580)	-	(16,580)	-
Computer & Software	-	-	-	-
Furniture & Fixtures	-	-	-	-
Equipment	12,167	-	12,167	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	(13,130)	111,846	(124,975)	-111.7%
Incr(Dec) in Fixed Assets	(17,542)	111,846	(129,388)	-115.7%
Total Budget	7,393,087	9,611,484	(2,218,398)	-23.1%
FTE's	13.91	20.20	(6.29)	-31.1%

Explanation of Variances by Category – Critical Infrastructure Department (CID) and ES-ISAC

- **Funding –** Workshop fees were $40.6k. 90.1%, over budget due to higher attendance at the Grid Security Conference than budgeted.
- **Personnel** expenses were collectively $1.2M, 28.2%, under budget due to having 6.29, 31.1%, fewer FTEs on staff than budgeted as a result of staff vacancies. The under budget variances in salaries, benefits and retirement expenses are generally consistent with the under budget variance for actual FTEs compared to budget. The under budget variance in payroll taxes is less than the other personnel expense categories due to the higher maximum salary subject to the tax than was assumed in the budget.
- **Meetings, Travel and Conferencing Expenses**
  - Meeting expenses were $32.9k, 22.7%, higher than budget due to higher costs of the Grid Security Conference. This higher than budgeted expense was offset by higher workshop fees collected from attendees as described above.
  - Travel expenses were $71.7k, 21.8%, under budget due to having fewer FTEs on staff than budgeted.
  - Conferencing expenses were $10.5k, 32.2%, under budget for no specific reason other than having fewer FTEs on staff.
- **Operating Expenses**
  - Consultant and contract expenses were $282.7k, 28.9%, under budget due to lower than budgeted expenses to support the ESCC Committee and due to lower than budgeted expenses related to cyber risk preparedness assessments, communications and software support services.
  - Office costs were $11.6k, 13.4%, over budget due to higher than budgeted software maintenance costs partially offset lower than budgeted telecommunications expense as a result of having fewer FTEs on staff than budgeted and lower overall telecommunications expense for NERC as described above.
- **Fixed Assets** – Over budget $12.2k for equipment purchased for the ES-ISAC portal that was not budgeted.

Training, Education and Operator Certification

Statement of Activities and Fixed Asset Budget

TRAINING, EDUCATION and OPERATOR CERTIFICATION	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	1,665,959	1,665,959	-	-
Penalties	12,008	12,008	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	1,659,137	1,620,000	39,137	2.4%
Services & Software	-	-	-	-
Workshop Fees	-	-	-	-
Interest	177	1,251	(1,074)	-85.8%
Miscellaneous	-	-	-	-
Total Funding	3,337,281	3,299,218	38,063	1.2%
Expenses				
Personnel Expenses				
Salaries	694,305	806,116	(111,811)	-13.9%
Payroll Taxes	54,119	56,919	(2,800)	-4.9%
Employee Benefits	114,123	143,194	(29,071)	-20.3%
Savings & Retirement	64,881	91,840	(26,959)	-29.4%
Total Personnel Expenses	927,428	1,098,069	(170,641)	-15.5%
Meeting Expenses				
Meetings	70,384	36,000	34,384	95.5%
Travel	19,759	51,000	(31,241)	-61.3%
Conference Calls	36,576	25,500	11,076	43.4%
Total Meeting Expenses	126,719	112,500	14,219	12.6%
Operating Expenses				
Consultants and Contracts	417,509	848,830	(431,322)	-50.8%
Rent & Improvements	-	-	-	-
Office Costs	86,986	98,300	(11,314)	-11.5%
Professional Services	-	-	-	-
Miscellaneous	551	500	51	10.3%
Depreciation	1,919	-	1,919	-
Total Operating Expenses	506,965	947,630	(440,665)	-46.5%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	1,515,022	1,534,092	(19,070)	-1.2%
Total Expenses	3,076,134	3,692,291	(616,157)	-16.7%
Net Change in Assets	261,147	(393,073)	654,220	-166.4%
Fixed Assets				
Depreciation	(1,919)	-	(1,919)	-
Computer & Software	-	-	-	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	(6,258)	45,181	(51,439)	-113.9%
Incr(Dec) in Fixed Assets	(8,177)	45,181	(53,358)	-118.1%
Total Budget	3,067,957	3,737,472	(669,515)	-17.9%
FTE's	6.63	8.16	(1.53)	-18.8%

Explanation of Variances by Category – Training, Education and Operator Certification

- **Personnel –** Salaries, payroll taxes, benefits and retirement costs were collectively under budget $170.6k, 15.5%, due to having 1.53, 18.8%, fewer FTEs on staff than budgeted as a result of staff vacancies. In addition to having fewer FTEs on staff than budgeted, personnel expenses were also impacted by the following:
    - Payroll Taxes – The under budget variance due to having fewer FTEs on staff than budgeted was partially offset by higher than budgeted FICA taxes due to a higher maximum salary subject to the tax than was assumed in the budget.
    - Savings and Retirement – Also under budget due to timing of hiring which impacts eligibility in the retirement plan.
- **Meetings, Travel and Conferencing** expenses were collectively $14.2k, 12.6% over budget.
    - Meetings expense was $34.4k, 95.5%, over budget as a result of having quarterly meetings of the Personnel Certification Governance Committee, which oversees the system operator certification program, in hotels instead of stakeholder facilities. All expenses of the system operator certification program are funded by fees collected for testing and certification.
    - Travel expenses were $31.2k, 61.3%, under budget due to having fewer FTEs on staff and in response to ongoing focus on travel expense management.
    - Conferencing expenses were $11.1k, 43.4%, over budget due to an increase in webinars to support NERC staff training and education activities.
- **Operating Expenses**
    - Consultant and contract expenses were under budget $431.3k, 50.8%, due to: (i) lower than budgeted expenses related to the system operator database improvement project and examination development project; (ii) lower than budgeted system operator testing expenses resulting from a new vendor contract signed after the 2014 budget was developed; and (iii) lower than budgeted costs for industry and staff training.
    - Office costs were under budget due to: (i) lower telecommunications expense as a result of having fewer FTEs on staff than budgeted and due to lower than budgeted telecommunications expenses for NERC in total; (ii) lower than budgeted dues; and (iii) lower than budgeted copying costs due to use of in-house equipment.

General and Administrative, Executive, and Policy and External Affairs

Statement of Activities and Fixed Asset Budget

GENERAL and ADMINISTRATIVE, including Executive and Policy & External Affairs	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	(2,216,461)	(2,216,461)	-	-
Miscellaneous	58	-	58	-
Total Funding	(2,216,403)	(2,216,461)	58	-
Expenses				
Personnel Expenses				
Salaries	2,939,041	2,031,742	907,299	44.7%
Payroll Taxes	146,646	89,250	57,396	64.3%
Employee Benefits	283,064	245,309	37,755	15.4%
Savings & Retirement	50,907	158,550	(107,643)	-67.9%
Total Personnel Expenses	3,419,658	2,524,851	894,807	35.4%
Meeting Expenses				
Meetings	248,436	268,000	(19,564)	-7.3%
Travel	407,023	421,482	(14,459)	-3.4%
Conference Calls	17,422	24,206	(6,784)	-28.0%
Total Meeting Expenses	672,881	713,688	(40,807)	-5.7%
Operating Expenses				
Consultants and Contracts	31,855	75,000	(43,145)	-57.5%
Rent & Improvements	2,737,780	2,617,299	120,481	4.6%
Office Costs	440,270	502,000	(61,730)	-12.3%
Professional Services	1,222,974	1,170,000	52,974	4.5%
Miscellaneous	5,384	5,500	(116)	-2.1%
Depreciation	474,056	419,399	54,657	13.0%
Total Operating Expenses	4,912,321	4,789,198	123,123	2.6%
Other Non-Operating Expenses	92,889	144,000	(51,111)	-35.5%
Indirect Expenses	(9,097,749)	(8,171,737)	(926,012)	11.3%
Total Expenses	-	-	-	-
Net Change in Assets	(2,216,403)	(2,216,461)	58	-
Fixed Assets				
Depreciation	(474,056)	(419,399)	(54,657)	13.0%
Computer & Software	-	-	-	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	36,377	-	36,377	-
Allocation of Fixed Assets	437,680	419,399	18,281	4.4%
Incr(Dec) in Fixed Assets	-	-	-	-
Total Budget	-	-	-	-
FTE's	14.48	10.56	3.92	37.1%

Explanation of Variances by Category – General and Administrative, Executive, and Policy and External Affairs

- **Personnel –** Salaries, payroll taxes, benefits and retirement were collectively $894.8k, 35.4%, over budget due to having 3.92, 37.1%, higher FTEs allocated to general and administrative support than budgeted for this department. During 2014, budgeted FTE positions were transferred from other programs to provided added support for NERC and Regional Entity operations coordination and NERC external affairs department.
    - Salaries were $907.3k, 44.7% over budget due to: (i) having more FTEs on staff than budgeted; (ii) higher temporary office services utilized to support the administrative staff in all departments; and (iii) an increase in accrued but unused paid time off applicable to all departments.
    - Payroll taxes were $57.4k, 64.3%, over budget due to having more FTEs on staff than budgeted and due to a higher maximum salary subject to the tax than was assumed in the budget.
    - Benefits were $37.8k, 15.4%, over budget due to having more FTEs on staff than budgeted, partially offset by lower than budgeted renewal costs associated with NERC's health plans.
    - Retirement expenses were $107.6k, 67.9%, under budget due to forfeiture of unvested funds related to personnel attrition across the entire organization.
- **Meeting, Travel and Conferencing Expenses** were collectively $40.8k, 5.7%, under budget.
    - Meeting expenses were $19.6k, 7.3%, under budget due to lower than budgeted costs associated with the quarterly Board of Trustee meetings as noted above.
    - Travel expenses were under budget due to focus on travel expense management.
- **Operating Expenses**
    - Consultant and contract expenses were under budget $43.1k, 57.5%, due to a reduction in the need for outside consulting to support external affairs as a result of certain duties now being performed internally, partially offset by costs associated with an ERO effectiveness survey that was not budgeted.
    - Rent was $120.5k, 4.6%, over budget due to: (i) a reduction in sublease revenue from NERC's former Washington, DC office in connection with negotiation and execution of a sublease amendment as a result of the subtenant's bankruptcy reorganization; and (ii) due to an increase in property taxes in Atlanta based on an updated assessment by Fulton County. With respect to the sublease agreement, the company received an upfront payment in connection with the execution of its current lease space in Washington, D.C. to offset potential liabilities associated with the sublease. This upfront payment is included in the company's working capital reserves and is being amortized over the term of the lease and is sufficient to offset the reduction in sublease revenue resulting from the subtenant bankruptcy.
    - Office costs were $61.7k, 12.3%, under budget due to lower than budgeted telecommunications costs, office supply costs, copying costs and sales and use taxes.

These lower than budgeted costs were partially offset by higher than budgeted bank fees associated with closing of the capital financing loan in January, 2014.

  - Professional services were $53.0k, 4.5% over budget due to slightly higher than budgeted trustee fees and trustee search fees as previously described and higher than budgeted outside legal fees associated with closing of the capital financing loan in January, 2014.

- **Fixed Assets** were over budget due to $36.4k in leasehold improvements associated with the DC office expansion that were budgeted to occur in 2015.

Legal and Regulatory

Statement of Activities and Fixed Asset Budget

LEGAL and REGULATORY	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	-	-	-	-
Penalties	-	-	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	-	-	-	-
Interest	-	-	-	-
Miscellaneous	-	-	-	-
Total Funding	-	-	-	-
Expenses				
Personnel Expenses				
Salaries	2,461,580	2,637,399	(175,819)	-6.7%
Payroll Taxes	142,134	136,718	5,416	4.0%
Employee Benefits	216,565	265,856	(49,291)	-18.5%
Savings & Retirement	253,810	296,887	(43,077)	-14.5%
Total Personnel Expenses	3,074,089	3,336,860	(262,771)	-7.9%
Meeting Expenses				
Meetings	3,093	5,000	(1,907)	-38.1%
Travel	103,235	120,000	(16,765)	-14.0%
Conference Calls	6,477	12,953	(6,476)	-50.0%
Total Meeting Expenses	112,805	137,953	(25,148)	-18.2%
Operating Expenses				
Consultants and Contracts	-	-	-	-
Rent & Improvements	-	-	-	-
Office Costs	54,457	63,500	(9,043)	-14.2%
Professional Services	700,346	760,000	(59,654)	-7.8%
Miscellaneous	-	500	(500)	-100.0%
Depreciation	4,458	-	4,458	-
Total Operating Expenses	759,261	824,000	(64,739)	-7.9%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	(3,946,155)	(4,298,813)	352,658	-8.2%
Total Expenses	-	-	-	-
Net Change in Assets	-	-	-	-
Fixed Assets				
Depreciation	(4,458)	-	(4,458)	-
Computer & Software	-	-	-	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	4,458	-	4,458	-
Incr(Dec) in Fixed Assets	-	-	-	-
Total Budget	-	-	-	-
FTE's	14.12	15.15	(1.03)	-6.8%

Explanation of Variances by Category – Legal and Regulatory

- **Personnel** expenses were collectively $262.8k, 7.9%, under budget primarily due to having 1.0, 6.8%, fewer FTEs on staff than budgeted. In addition to having fewer FTEs on staff than budgeted, personnel expenses were also impacted by the following:
    - Payroll Taxes – Higher than budgeted FICA taxes due to a higher maximum salary subject to the tax than was assumed in the budget.
    - Benefits - The under budget variance due to having fewer FTEs on staff than and a lower average cost of NERC's health plan per FTE in this program than the average cost per FTE in the budget.
    - Retirement expenses were also under budget due to timing of hiring which impacts eligibility in the retirement plan.
- **Meeting, travel and conferencing** expenses were collectively $25.1k, 18.2%, under budget primarily due to lower than budgeted travel expenses related to focus on travel expense management.
- **Office costs** were $9.0k, 14.2%, under budget due to lower telecommunications expense as a result of having fewer FTEs on staff than budgeted and lower overall telecommunications expenses for NERC as described above.
- **Professional services** were $59.7k, 7.8%, due to lower than budgeted outside legal fees associated with lobbying and other support services.

Information Technology

Statement of Activities and Fixed Asset Budget

INFORMATION TECHNOLOGY	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	-	-	-	-
Penalties	-	-	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	-	-	-	-
Interest	-	-	-	-
Miscellaneous	-	-	-	-
Total Funding	-	-	-	-
Expenses				
Personnel Expenses				
Salaries	2,456,664	2,013,859	442,805	22.0%
Payroll Taxes	152,717	136,366	16,351	12.0%
Employee Benefits	329,546	317,097	12,449	3.9%
Savings & Retirement	198,492	229,767	(31,275)	-13.6%
Total Personnel Expenses	3,137,419	2,697,089	440,330	16.3%
Meeting Expenses				
Meetings	8,393	5,000	3,393	67.9%
Travel	50,639	59,243	(8,604)	-14.5%
Conference Calls	31,667	4,800	26,867	559.7%
Total Meeting Expenses	90,699	69,043	21,656	31.4%
Operating Expenses				
Consultants and Contracts	2,017,016	1,944,000	73,016	3.8%
Rent & Improvements	-	-	-	-
Office Costs	2,190,891	2,279,770	(88,879)	-3.9%
Professional Services	10,796	-	10,796	-
Miscellaneous	-	500	(500)	-100.0%
Depreciation	1,028,050	1,330,443	(302,393)	-22.7%
Total Operating Expenses	5,246,753	5,554,713	(307,960)	-5.5%
Other Non-Operating Expenses	9,292	-	9,292	-
Indirect Expenses	(8,484,162)	(8,320,845)	(163,317)	2.0%
Total Expenses	-	-	-	-
Net Change in Assets	-	-	-	-
Fixed Assets				
Depreciation	(1,028,050)	(1,330,443)	302,393	-22.7%
Computer & Software	1,034,842	2,258,800	(1,223,958)	-54.2%
Furniture & Fixtures	-	-	-	-
Equipment	340,225	213,000	127,225	59.7%
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	(347,017)	(1,141,357)	794,340	-
Incr(Dec) in Fixed Assets	-	-	-	-
Total Budget	-	-	-	-
FTE's	18.91	18.07	0.84	4.6%

Explanation of Variances by Category – Information Technology

- **Personnel**
  - Salaries expenses were $442.8k, 22.0%, over budget due to the reallocation of additional FTEs to strengthen IT program and software application development, oversight and execution. This resulted in the IT department having 4.6% more FTEs on staff than budgeted, higher average salaries per FTE due to the addition of senior personnel, and higher than budgeted temporary office services to support ongoing operations during periods of staff vacancies.
  - Payroll taxes were over budget due to higher FTEs than budget and due to the higher maximum salary subject to the tax than was assumed in the budget.
  - Retirement costs were under budget due to timing of hiring which impacts eligibility in the retirement plan.
- **Meeting, travel and conferencing** expenses were collectively $21.6k, 31.4%, over budget primarily due to higher conferencing expenses. The monthly fee charged for webinar services was budgeted in general and administrative but was charged to IT during the year.
- **Professional services** was $10.8k over budget due to outside services support of audio visual equipment during staff meetings that was not budgeted.
- **Fixed Assets**
  - Computer and software $1.2M, 54.2%, under budget due to a reduction in software development and associated hardware expenditures as NERC updated and refined the ERO Enterprise and internal software application development strategies.
  - Equipment purchases $127.2k, 59.7%, over budget related to installation of various IT infrastructure projects, including disaster recovery and network simplification which were not specifically budgeted but were approved as a use of operating reserves in accordance with NERC's working capital and operating reserve policy.

Human Resources

Statement of Activities and Fixed Asset Budget

HUMAN RESOURCES	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	-	-	-	-
Penalties	-	-	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	-	-	-	-
Interest	-	-	-	-
Miscellaneous	-	-	-	-
Total Funding	-	-	-	-
Expenses				
Personnel Expenses				
Salaries	538,267	595,009	(56,742)	-9.5%
Payroll Taxes	25,332	23,428	1,904	8.1%
Employee Benefits	67,358	50,539	16,819	33.3%
Savings & Retirement	43,537	42,721	816	1.9%
Total Personnel Expenses	674,493	711,697	(37,204)	-5.2%
Meeting Expenses				
Meetings	1,186	2,000	(814)	-40.7%
Travel	9,928	10,897	(969)	-8.9%
Conference Calls	754	600	154	25.6%
Total Meeting Expenses	11,868	13,497	(1,630)	-12.1%
Operating Expenses				
Consultants and Contracts	298,365	257,500	40,865	15.9%
Rent & Improvements	-	-	-	-
Office Costs	9,059	16,500	(7,441)	-45.1%
Professional Services	61,856	80,280	(18,424)	-22.9%
Miscellaneous	11,794	25,500	(13,706)	-53.8%
Depreciation	7,733	-	7,733	-
Total Operating Expenses	388,807	379,780	9,027	2.4%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	(1,075,167)	(1,104,974)	29,807	-2.7%
Total Expenses	-	-	-	-
Net Change in Assets	-	-	-	-
Fixed Assets				
Depreciation	(7,733)	-	(7,733)	-
Computer & Software	-	-	-	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	7,733	-	7,733	-
Incr(Dec) in Fixed Assets	-	-	-	-
Total Budget	-	-	-	-
FTE's	3.00	2.88	0.12	4.2%

Explanation of Variances by Category – Human Resources (HR)

- **Personnel** expenses were collectively $37.2k, 5.2%, under budget.
  - Salaries expense was $56.7k, 9.5%, under budget due to lower than budgeted temporary office services, which were budgeted in HR but charged to the department where services were utilized.
  - Benefits were $16.8k, 33.3%, over budget due to a higher average cost of NERC's health plan per FTE in this program than the average cost per FTE in the budget.
- **Operating Expenses**
  - Consultant and contract expenses were $40.9k, 15.9%, over budget due to vendor support for benefits enrollment process improvements.
  - Professional services were $18.4k, 22.9%, lower than budget due to lower than budgeted costs of the HR information system and various third-party benefit providers.
  - Miscellaneous expenses consisting of employee rewards and recognition expenses and costs associated with community responsibility activities were under budget $13.7k, 53.8%. All costs of participation in 2014 community responsibility activities were funded by NERC employees. A portion of the cost of the year-end employee appreciation events was not invoiced or paid until 2015.

Finance and Accounting

Statement of Activities and Fixed Asset Budget

ACCOUNTING and FINANCE	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
Assessments	-	-	-	-
Penalties	-	-	-	-
Third-Party Funding (CRISP)	-	-	-	-
Testing	-	-	-	-
Services & Software	-	-	-	-
Workshop Fees	-	-	-	-
Interest	-	-	-	-
Miscellaneous	-	-	-	-
Total Funding	-	-	-	-
Expenses				
Personnel Expenses				
Salaries	1,678,905	1,379,476	299,429	21.7%
Payroll Taxes	100,486	81,128	19,358	23.9%
Employee Benefits	212,427	219,002	(6,575)	-3.0%
Savings & Retirement	173,967	155,391	18,576	12.0%
Total Personnel Expenses	2,165,784	1,834,997	330,787	18.0%
Meeting Expenses				
Meetings	1,903	5,650	(3,747)	-66.3%
Travel	49,918	62,500	(12,582)	-20.1%
Conference Calls	5,294	4,000	1,294	32.3%
Total Meeting Expenses	57,115	72,150	(15,035)	-20.8%
Operating Expenses				
Consultants and Contracts	198,127	400,000	(201,873)	-50.5%
Rent & Improvements	-	-	-	-
Office Costs	33,601	29,500	4,101	13.9%
Professional Services	372,785	280,000	92,785	33.1%
Miscellaneous	332	500	(168)	-33.5%
Depreciation	2,201	-	2,201	-
Total Operating Expenses	607,047	710,000	(102,953)	-14.5%
Other Non-Operating Expenses	-	-	-	-
Indirect Expenses	(2,829,946)	(2,617,147)	(212,799)	8.1%
Total Expenses	-	-	-	-
Net Change in Assets	-	-	-	-
Fixed Assets				
Depreciation	(2,201)	-	(2,201)	-
Computer & Software	-	-	-	-
Furniture & Fixtures	-	-	-	-
Equipment	-	-	-	-
Leasehold Improvements	-	-	-	-
Allocation of Fixed Assets	2,201	-	2,201	-
Incr(Dec) in Fixed Assets	-	-	-	-
Total Budget	-	-	-	-
FTE's	15.50	12.48	3.02	24.2%

Explanation of Variances by Category – Finance and Accounting

- **Personnel**
  - Salaries expense was $229.4k, 21.7%, over budget due the addition of personnel to strengthen operating and internal controls, including staff additions budgeted for 2015 which were added during the latter part of 2014.This resulted in 3.0, 24.2%, more FTEs on staff than budgeted.
  - Payroll taxes were $19.4k, 23.9%, over budget due to having more FTEs on staff than budgeted.
  - Retirement expenses were $18.6k, 12.0%, over budget due to having more FTEs on staff than budgeted but the over budget variance was less than the increase in FTEs due to timing of hiring which impacts eligibility in the retirement plan.
- **Meeting, travel and conferencing** expenses were collectively $15.0k, 20.8%, under budget primarily due to lower than budgeted travel expenses related to focus on travel expense management.
- **Operating Expenses**
  - Consultant and contract expenses were $201.9k, 50.5%, under budget due to lower than budgeted consulting support.
  - Professional services were $92.8k, 33.1%, over budget due to higher than budgeted outside legal fees associated with regulatory filing requirements associated with Peak Reliability, and higher than budgeted fees associated with design and implementation of an executive supplemental retirement plan.

Financial Statements and Report of
Independent Certified Public Accountants

North American Electric Reliability Corporation

December 31, 2014 and 2013

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REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Board of Trustees of
North American Electric Reliability Corporation

We have audited the accompanying financial statements of North American Electric Reliability Corporation (a New Jersey non-profit corporation), which comprise the statements of financial position as of December 31, 2014 and 2013, and the related statements of activities, and cash flows for the years then ended, and the related notes to the financial statements.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of North American Electric Reliability Corporation as of December 31, 2014 and 2013, and the change in its net assets and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Supplementary information

Our audits were conducted for the purpose of forming an opinion on the financial statements as a whole. The supplemental schedule of selected expenses shown on page 15 is presented for purposes of additional analysis and is not a required part of the financial statements. Such supplementary information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the financial statements. The information has been subjected to the auditing procedures applied in the audit of the financial statements and certain additional procedures. These additional procedures included comparing and reconciling the information directly to the underlying accounting and other records used to prepare the financial statements or to the financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the supplementary information is fairly stated, in all material respects, in relation to the financial statements as whole.

Grant Thornton LLP

Atlanta, Georgia
May 7, 2015

Statements of Financial Position

December 31,	2014	2013
Assets		
Current Assets		
Cash and cash equivalents	**$ 38,310,796**	$ 26,182,060
Restricted cash	**500,000**	-
Accounts receivable, net of allowance for doubtful accounts of $0	**5,059,002**	3,353,895
Prepaid expenses	**756,727**	869,876
Total Current Assets	**44,626,525**	30,405,831
Long-Term Assets		
Property and equipment, net	**5,929,366**	5,645,116
Security deposits	**99,136**	99,136
457b Plan Assets	**522,756**	320,660
Total Long-Term Assets	**6,551,258**	6,064,912
Total Assets	**$ 51,177,783**	$ 36,470,743
Liabilities and net assets		
Current Liabilities		
Accounts payable and accrued expenses	**$ 8,930,613**	$ 6,943,283
Accrued retirement liabilities	**1,907,563**	1,788,624
Current portion of long-term debt	**421,667**	-
Deferred revenue	**10,182,338**	5,287,044
Deferred rent - current	**249,269**	182,421
Deferred compensation - current	**14,257**	20,386
Capital lease obligations - current	**56,457**	47,108
Regional assessments collected in advance	**11,438,454**	9,427,293
Total Current Liabilities	**33,200,618**	23,696,159
Long-Term Liabilities		
Deferred rent - non-current	**3,569,492**	3,817,478
Deferred compensation - non-current	**783,446**	597,514
Insurance reserve	**500,000**	-
Long-term debt	**456,806**	-
Capital lease obligations - non-current	**216,481**	-
Total Long-Term Liabilities	**5,526,225**	4,414,992
Total Liabilities	**38,726,843**	28,111,151
Net Assets		
Unrestricted	**8,485,940**	7,914,592
Temporarily restricted	**3,965,000**	445,000
Total Net Assets	**12,450,940**	8,359,592
Total Liabilities and Net Assets	**$ 51,177,783**	$ 36,470,743

The accompanying notes are an integral part of these financial statements.

Statements of Activities

	For the Year Ended December 31, 2014			For the Year Ended December 31, 2013		
	Unrestricted	Temporarily Restricted	Total	Unrestricted	Temporarily Restricted	Total
Revenues:						
NERC assessments	**$ 51,401,382**	$ -	**$ 51,401,382**	$ 47,604,156	$ -	$ 47,604,156
Penalty income	**-**	**3,810,000**	**3,810,000**	-	445,000	445,000
Third-Party funding	**1,587,876**	**-**	**1,587,876**	-	-	-
Testing / fees	**1,659,137**	**-**	**1,659,137**	1,822,154	-	1,822,154
Services and software	**77,000**	**-**	**77,000**	86,075	-	86,075
Workshops	**231,090**	**-**	**231,090**	320,725	-	320,725
Rental income	**242,589**	**-**	**242,589**	293,000	-	293,000
Interest	**2,830**	**-**	**2,830**	3,197	-	3,197
Loss on disposal of fixed assets	**(9,142)**	**-**	**(9,142)**	(99,708)	-	(99,708)
Miscellaneous revenues	**58**	**-**	**58**	224	-	224
Net assets (penalties) released from restrictions	**290,000**	**(290,000)**	**-**	2,512,500	(2,512,500)	-
Total revenues	**55,482,820**	**3,520,000**	**59,002,820**	52,542,323	(2,067,500)	50,474,823
Expenses:						
Salaries	**25,729,089**	**-**	**25,729,089**	25,465,466	**-**	25,465,466
Employee costs	**4,665,434**	**-**	**4,665,434**	4,395,066	**-**	4,395,066
Retirement and savings plans	**2,336,382**	**-**	**2,336,382**	2,252,973	**-**	2,252,973
Travel and meetings	**3,486,930**	**-**	**3,486,930**	3,414,306	**-**	3,414,306
Services	**10,485,664**	**-**	**10,485,664**	10,511,000	**-**	10,511,000
Rent	**2,980,370**	**-**	**2,980,370**	3,015,106	**-**	3,015,106
Office costs	**1,472,572**	**-**	**1,472,572**	1,622,635	**-**	1,622,635
Computer	**1,796,180**	**-**	**1,796,180**	1,607,057	**-**	1,607,057
Depreciation and amortization	**1,845,951**	**-**	**1,845,951**	1,945,946	**-**	1,945,946
Property tax expense	**52,312**	**-**	**52,312**	48,606	**-**	48,606
Provision for bad debts	**10,554**	**-**	**10,554**	45,610	**-**	45,610
Miscellaneous expenses	**19,861**	**-**	**19,861**	20,608	**-**	20,608
Interest	**30,173**	**-**	**30,173**	3,114	**-**	3,114
Total expenses	**54,911,472**	**-**	**54,911,472**	54,347,493	**-**	54,347,493
Change in net assets	**571,348**	**3,520,000**	**4,091,348**	(1,805,170)	(2,067,500)	(3,872,670)
Net assets, beginning of year	**7,914,592**	**445,000**	**8,359,592**	9,719,762	2,512,500	12,232,262
Net assets, end of year	**$ 8,485,940**	**$ 3,965,000**	**$ 12,450,940**	$ 7,914,592	$ 445,000	$ 8,359,592

The accompanying notes are an integral part of these financial statements.

Statements of Cash Flow

For the Years Ended December 31,	2014	2013
Cash flows from operating activities		
Change in net assets	**$ 4,091,348**	$ (3,872,670)
Adjustments to reconcile change in net assets to net cash provided by operating activities:		
Depreciation and amortization	**1,845,951**	1,945,946
Straight-line rent accrual	**(181,138)**	258,362
Loss on disposal of fixed assets	**9,142**	99,708
Provision for bad debts	**10,554**	45,610
Change in value of insurance policies	**-**	337,414
Increase (decrease) in cash attributable to changes in operating assets and liabilities:		
Accounts receivable	**(1,715,661)**	882,097
Prepaid expenses	**113,149**	18,211
Security deposits	**-**	15,767
Receipt of funds for regional entities	**94,703,215**	152,966,084
Disbursements of funds to regional entities	**(94,703,215)**	(152,966,084)
Accounts payable and accrued expenses	**1,923,684**	803,926
Deferred revenue	**4,895,294**	109,293
Insurance Reserve	**500,000**	-
Regional assessments collected in advance	**2,011,161**	(187,536)
Deferred compensation	**(22,293)**	(324,105)
Accrued retirement liabilities	**118,939**	379,076
Net cash provided by operating activities	**13,600,130**	511,099
Cash flows from investing activities		
Purchases of property and equipment	**(1,806,735)**	(2,200,782)
Proceeds from sales of property and equipment	**11,519**	975
Net cash used in investing activities	**(1,795,216)**	(2,199,807)
Cash flows from financing activities		
Proceeds from financing activities	**1,265,000**	-
Debt service	**(386,527)**	-
Capital lease payments	**(54,651)**	(65,928)
Net cash provided by (used in) financing activities	**823,822**	(65,928)
Net (decrease) increase in cash and cash equivalents	**12,628,736**	(1,754,636)
Cash and cash equivalents, beginning of year	**26,182,060**	27,936,696
Cash and cash equivalents, end of year	**$ 38,810,796**	$ 26,182,060
Supplemental disclosure of non-cash information		
Fixed asset purchases within accounts payable	**$ 63,646**	$ 270,753
Capital lease obligation for equipment	**280,481**	**-**
Supplemental disclosure of cash paid		
Interest	**$ 30,173**	$ 3,114
Reconciliation of Cash		
Cash and cash equivalents	**$ 38,310,796**	$ 26,182,060
Restricted cash	**500,000**	-
Cash and cash equivalents, end of year	**$ 38,810,796**	$ 26,182,060

The accompanying notes are an integral part of these financial statements.

Notes to the Financial Statements

1 Organization and Nature of Business

North American Electric Reliability Corporation (the "Corporation" or "NERC") is an international, independent, not-for-profit organization, whose mission is to ensure the reliability of the bulk power system in North America. NERC relies on the diverse and collective expertise of electricity industry participants, subject to government oversight and audit. The Corporation is certified by the United States Federal Energy Regulatory Commission ("FERC") as the Electric Reliability Organization ("ERO") within the United States. In the United States, the Corporation has the authority to levy fines and penalties against any of the individual users, owners and operators of the bulk power system for non-compliance with the reliability standards that govern the bulk power system. The Corporation has also been recognized as the ERO by governmental authorities in Canada.

To achieve the Corporation's mission, it develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; and educates, trains and certifies industry personnel. Entities subject to the Corporation's reliability standards account for virtually all the electricity supplied in the United States, Canada and a portion of Baja California, Norte, Mexico.

The Corporation is the successor to the North American Electric Reliability Council (the "Council") which was formed in 1968 in the aftermath of the November 1965 blackout that affected the northeastern United States and Ontario, Canada. On October 31, 2006, the Council entered into an agreement and plan of merger with the Corporation, a New Jersey non-profit corporation. At the effective date of the merger, January 1, 2007, the separate corporate existence of the Council ceased, and the Corporation became the surviving entity. All of the property, assets, rights, privileges, powers, franchises and immunities of the Council became the property of the Corporation. All debts, liabilities and obligations of the Council were also assumed by the Corporation. The Corporation is organized and operates as a business league under Internal Revenue Code Section 501(c)(6). The activities of the Corporation are directed by an independent Board of Trustees.

The membership of the Corporation is unique. It is a not-for-profit corporation whose members include users, owners and operators of the bulk power system, eight regional entities, large and small end-use customers, state and provincial governmental authorities and other interested parties.

Annually, the Board of Trustees approves an operating budget for the Corporation that includes a provision for working capital and operating reserves, which are recovered through assessments to Load-Serving Entities ("LSE"). The determination of the annual working capital and operating reserve requirements and the authorization of management to access these funds is governed by the Corporation's "Working Capital and Operating Reserve Policy." The Corporation assesses each LSE a proportional share of its annual operating budget based on "net energy for load." During 2014, the assessments to LSEs made up approximately 87.1% of the total funding for the Corporation. Assessments to U.S. entities in 2014 were offset by $290,000 in penalties received in prior years, but restricted from use until 2014 per the Corporation's policy on the "Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standards." The Corporation also generates funding from the collection of fees charged for various services. These services include management of some contracts associated with the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), the maintenance of a certification program for system operators, the development of reports and software programs, and the hosting of workshops to educate the industry on various reliability matters.

The Corporation has entered into separate delegation agreements, which have been approved by FERC, with eight regional entities: Florida Reliability Coordinating Council ("FRCC"), Midwest Reliability Organization ("MRO"), Northeast Power Coordinating Council ("NPCC"), Reliability First Corporation ("RFC"), SERC Reliability Corporation ("SERC"), Southwest Power Pool Regional Entity ("SPP"), Texas Reliability Entity ("TRE") and Western Electricity Coordinating Council ("WECC") (collectively the "Regional Entities"). Through these agreements, the Corporation has delegated certain ERO responsibilities and functions to the Regional Entities.

The Corporation must annually approve the eight Regional Entities' budgets and submit them, along with its budget and schedule of LSE assessments, to FERC for final approval of the budgets and the U.S. portion of the assessments. The Corporation has the sole responsibility to invoice, collect and disburse the monies approved in the Regional Entities' budgets. These pass-through amounts are not included as revenue and expense in the statement of activities (see Note 6).

2 Summary of Significant Accounting Policies

Basis of Accounting and Presentation

The financial statements of the Corporation have been prepared on the accrual basis of accounting in conformity with accounting principles generally accepted in the United States of America. Net assets, revenues, expenses, gains and losses are classified based on the existence or absence of restrictions. The Corporation reports information regarding its financial position and activities according to three classes of net assets: unrestricted net assets, temporarily restricted net assets and permanently restricted net assets. There were no permanently restricted net assets as of December 31, 2014 or 2013. Net assets totaling $3,965,000 and $445,000 were temporarily restricted as of December 31, 2014 and 2013, respectively, to offset future assessments.

Cash and Cash Equivalents

The Corporation considers all highly liquid investments purchased with original maturities of three months or less to be cash and cash equivalents. The Corporation maintains its cash balances with one bank. The accounts at the bank are insured up to certain limits by the Federal Deposit Insurance Corporation. Balances in these accounts may exceed Federally-insured limits from time to time. A total of $500,000 has been set aside for the insurance reserve in current assets and non-current liabilities and is restricted from use for any other purpose.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition

The Corporation recognizes assessment revenue billed to the LSEs on a pro-rata basis over the calendar year. Fees generated for contract management, testing, certifications, services and software, workshops and other services are recognized when the test is taken, service rendered and/or workshops are completed.

Penalty income is derived from FERC's approval of assessment of penalties to registered entities regarding enforcement of NERC's Reliability Standards. The penalty income from a registered entity is recorded following closure of the enforcement matter including exhaustion of appeals. The funds are temporarily restricted due to FERC's requirement that the funds be used to reduce future NERC assessments.

Deferred Revenue

Deferred revenue represents assessments and fees billed and received in advance of the period in which it is earned. Deferred revenue is recognized as revenue in the period in which it is earned.

Accounts Receivable

Accounts receivable are recorded at the original invoice amount, less an estimated allowance for uncollectible accounts. Credit is generally extended on a short-term basis; thus accounts receivable do not bear interest. Accounts receivable are periodically evaluated for collectability based on past experience and an analysis of current accounts receivable collectability. Changes in the estimated collectability of accounts receivable are recorded in the results of operations for the period in which the estimate is revised. Accounts deemed uncollectible are charged to the allowance in the years they are deemed uncollectible.

Property and Equipment

Purchased property and equipment are capitalized at cost. Donated assets are capitalized at the fair market value of the assets on the date of contribution. The Corporation's minimum capitalization policy is for additions greater than $2,000.

Depreciation and amortization is provided by the straight-line method over the estimated useful lives of the related assets as follows:

	Years
Software development	3 years
Furniture and equipment	3-7 years
Leasehold improvements	Term of lease or estimated useful life of the asset, whichever is shorter

Expenditures for maintenance and repairs are charged to operations as incurred while renewals and betterments are capitalized.

Compensated Absences

Employees of the Corporation are entitled to paid time off depending on length of service. At December 31, 2014 and 2013, the Corporation has recorded accrued compensated absences of $565,999 and $543,126 related to days earned, which is included with accounts payable and accrued expenses on the statements of financial position.

Income Taxes

The Corporation has received a determination letter from the Internal Revenue Service concluding that it is exempt from Federal income taxes under Section 501(c)(6) of the Internal Revenue Code. The Corporation is subject to income taxes on revenues from unrelated business activities. The Corporation is subject to a proxy tax related to nondeductible lobbying and political expenses incurred. There was no proxy tax incurred in 2014 or 2013.

The Corporation recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authority, based on the technical merits of the position. The Corporation is no longer subject to federal and state tax examinations by the respective taxing authorities for the years prior to 2011. Tax years 2011 through 2014 remain subject to examination by major tax jurisdictions.

Reclassifications

Certain reclassifications have been made to prior years' functional classification of operational program expenses to conform to current year presentation. These classifications had no effect on previously reported changes in net assets.

Subsequent Events

The Corporation discloses material events that occur after the statement of financial position date but before financial statements are issued. In general, these events are recognized in the financial statements if the condition existed at the date of the statement of financial position, but are not recognized if the condition did not exist at the statement of financial position date. The Corporation discloses non-recognized events if required to keep the financial statements from being misleading. Management evaluated events occurring subsequent to December 31, 2014 through May 7, 2015, the date the financial statements were available for issuance.

On January 29, 2015, the Corporation entered into an agreement to expand the amount of leased space in Atlanta, Georgia with an expiration date in 2022, which is coterminous with the term of the original lease. On March 2, 2015, the Corporation entered into an agreement to expand the amount of leased space in Washington, DC with an expiration date in 2022, which is coterminous with the term of the original lease (see Note 8).

3 Property and Equipment

Property and equipment consist of the following at December 31:

December 31,	2014	2013
Software development	$ 4,392,007	$ 2,986,517
Furniture and equipment	6,805,180	6,860,119
Leasehold improvements	1,100,816	1,100,281
	12,298,003	10,946,917
Accumulated depreciation and amortization	(6,368,637)	(5,301,801)
	$ 5,929,366	$ 5,645,116

Depreciation and amortization expense for the years ended December 31, 2014 and 2013 was $1,845,951 and $1,945,946, respectively.

4 Non-Revolving Credit Facility and Line of Credit

On January 13, 2014, the company secured a non-revolving credit facility under the Capital Financing Program that was approved by the Board of Trustees and the FERC as part of the Corporation's 2014 Business Plan and Budget. The interest rate is floating and equal to LIBOR plus 275 basis points, which yielded a rate of 2.91% at closing. The total size of this facility is $7,500,000, with the total authorized borrowings each year limited to the amount approved by the Board of Trustees and FERC in that year's business plan and budget. This facility is collateralized by all existing and future assets and subject to a filing under the Uniform Commercial Code. Borrowings outstanding as of December 31, 2014 were $878,473.

The Corporation has a line of credit with a bank that expires in June 2015. The line of credit provides for up to $4,000,000 of availability to be used for working capital needs. In connection with the non-revolving credit facility secured on January 13, 2014, the line of credit was amended and restated. The line of credit accrues interest at a rate per annum equal to LIBOR plus 275 basis points, which yielded a rate of 2.91% at closing. The line of credit is collateralized by all existing and future assets and subject to a filing under the Uniform Commercial Code. As part of the amended and restated line of credit note, the Corporation is no longer required to maintain the $400,000 non-interest bearing account with the lender. In 2013, the $400,000 was classified within cash and cash equivalents on the statement of financial position as of December 31, 2013. There were no borrowings outstanding at December 31, 2014 or 2013. At December 31, 2014 and 2013, the available amount under the line of credit was reduced by open letters of credit totaling $140,772 which represent security deposits for the Corporation's office lease agreements.

Both loan agreements contain various positive and negative covenants, and the Corporation was in compliance with these covenants as of December 31, 2014.

5 Penalty Income

The Corporation received $3,810,000 and $445,000 of penalty income in 2014 and 2013, respectively, which is temporarily restricted. The penalty income will be utilized in accordance with the timing of the receipt of the income and FERC's requirement for the use of penalty income to reduce assessments. NERC transferred $290,000 of penalty income from temporarily restricted net assets to unrestricted net assets during 2014. During 2013, NERC transferred $2,512,500 of penalty income from temporarily restricted net assets to unrestricted net assets.

6 Regional Assessments Collected in Advance

In addition to the Corporation assessments billed to LSEs or designees, a regional assessment is also billed by the Corporation on behalf of the Regional Entities. The regional assessment is based on approved budgets of the eight Regional Entities and remitted to the Regional Entities by the Corporation. There is a credit risk if the Corporation does not collect the assessments from LSEs or designees before the regional assessments are due to the Regional Entities. However, the risk is minimal since the Corporation has the ability to reassess and rebill in a subsequent period for any uncollected assessments. Regional assessments billed and remitted for 2014 and 2013 were as follows:

For the Year Ended December 31,	2014	2013
Total regional assessments billed to WECC, ERCOT, individual LSE's and designees	$ 92,683,354	$ 113,584,703
Total regional assessments remitted to Regional Entities	(92,648,361)	(113,480,310)
Billings over remittances	$ 34,993	$ 104,393

As of December 31, 2014 and 2013, regional assessments collected in advance and not yet remitted to the Regional Entities based upon the remittance schedule set forth in the delegation agreements totaled $11,438,454 and $9,427,293, respectively.

7 Deferred Compensation

Agreements and Life Insurance Policies

During 2005, the Council entered into a deferred compensation agreement with a retiring executive that provided benefits payable over a period selected by the retiring employee, payable to the retiree or his surviving spouse. The Corporation assumed the liability upon merger with the Council. The original agreement was superseded in 2008 and a variable universal life policy was used to fund the liability. This life policy, including the cash surrender value, was assigned and transferred to the retired executive in January 2009. In accordance with the new agreement, the Corporation will continue to pay the policy premiums through 2015. At December 31, 2014 and 2013, the present value of the unfunded liability, using a discount rate of 0.75% was $14,257. The present value of the unfunded liability as of December 31, 2014 and 2013 is included in current deferred compensation on the statements of financial position.

Deferred Compensation Plan

The Corporation established a deferred compensation plan for certain employees in 2012 in accordance with Internal Revenue Code Section 457. The plan provides that eligible employees may make elective salary reduction contributions in accordance with limitations established by the Internal Revenue Code. In 2014, the plan was amended to allow the company to make discretionary, non-elective contributions to the plan on behalf of the employee. The asset and liability for this deferred compensation plan of $522,756 and $320,660 at December 31, 2014 and 2013, respectively, are included in 457b Plan Assets and non-current deferred compensation on the statements of financial position.

Retiree Medical Benefits

Effective September 1, 2007, the Board of Trustees approved and adopted a policy to provide medical coverage for a limited number of current and transitional retirees and their dependents up to a maximum monthly benefit of $550 paid directly to the applicable insurer. Assumptions used in recording the retiree medical benefits included the 2009 Social Security Administration Actuarial Period Life Table, annual inflation rate of 1.5% and discount rate of 3.8%. At December 31, 2014 and 2013 the accrued retiree medical benefits liability was $256,694 and $276,855, respectively, and is included in non-current deferred compensation on the statements of financial position. The retiree medical expense related to this policy was $9,507 and $26,616, respectively for the years ended December 31, 2014 and 2013.

8 Commitments

Operating Leases

The Corporation leases office space in Washington, D.C. and Atlanta, Georgia under non-cancellable lease agreements, with expiration dates through 2022. The lease for office space in Princeton, NJ expired in 2013.

In 2012 and 2015, the Corporation entered into agreements to expand the amount of leased space in Atlanta, Georgia with an expiration date in 2022, which is coterminous with the term of the lease for the original premises.

In 2015, the Corporation entered into an agreement to expand the amount of leased space in Washington, D.C. with an expiration date in 2022, which is coterminous with the term of the lease for the original premises.

In 2011, the Corporation entered into separate sub-lease agreements for a portion of the office space in Princeton, New Jersey, which expired in 2013, and for one of the two locations in Washington D.C., with an expiration date of February 2017. On June 23, 2014, the Corporation and sub-tenant agreed to amend the sublease agreement for the space in Washington D.C., to reduce the amount of space subleased to sub-tenant and to reduce the rate of rent due under the terms of the sublease agreement.

Approximate future minimum payments on office lease space at December 31, 2014 are as follows, net of rental income for sub-leased space and including lease agreements entered into subsequently in January, 2015:

Years Ending December 31,	Leased Space	Sub-leased Space	Net
2015	$ 3,219,000	$ (206,000)	$ 3,013,000
2016	3,467,000	(213,000)	3,254,000
2017	3,275,000	(36,000)	3,239,000
2018	3,300,000	-	3,300,000
2019	3,386,000	-	3,386,000
Thereafter	9,449,000	-	9,449,000
	$ 26,096,000	$ (455,000)	$ 25,641,000

The office leases are subject to escalation clauses covering increases in real estate taxes and operating costs over the base year. The Corporation had received tenant improvement allowances as of December 31, 2013 totaling $381,632. The difference between rent expense calculated ratably over the lease term and actual payments under the agreements are recorded as a deferred rent obligation on the statements of financial position in the amount of $3,818,761 and $3,999,899 at December 31, 2014 and 2013, respectively.

Office rent expense, net of sub-lease income of $242,589 and $293,000, was $2,534,672 and $2,574,909 for the years ended December 31, 2014 and 2013, respectively.

Capital Leases

The Corporation has entered into capital lease agreements for office equipment. Depreciation expense related to these capital leases was $51,227 and $65,407 for the years ended December 31, 2014 and 2013, respectively.

Assets leased by the Corporation under capital leases are included in fixed assets and capital lease obligation on the statements of financial position and consisted of the following:

December 31, 2014	
Copier leases	$ 280,481
Accumulated depreciation	(5,843)
Net Book Value	$ 274,638

The following is a schedule of future minimum lease payments under these capital leases, together with the future obligation net of interest and maintenance as of December 31, 2014:

Years ending December 31,	Future Minimum Payments
2015	$ 91,000
2016	91,000
2017	91,000
2018	83,000
Total Minimum Lease Payment	356,000
Less: Amounts representing interest and maintenance	(83,062)
Future Obligation Net of Interest and Maintenance	$ 272,938

Contractual Commitments

The Corporation has software license, maintenance support and data management service agreements with varying expiration dates through 2017. The following table is a schedule of future commitments under the terms of the agreements:

Years ending December 31,		Future Minimum Payments
2015	$	222,000
2016		227,000
2017		59,000
Total Service Agreements	$	508,000

9 Savings and Investment Plan

The Corporation sponsors an employee savings 401(k) plan (the "Plan") whereby eligible employees may elect to contribute up to the Internal Revenue Service Code 402(g)(1) limit. The Corporation contributes a 75% match of the first 6% of a participant's elective contribution. The Corporation also makes a discretionary contribution equal to a percentage of the eligible compensation of all qualifying participants. The additional discretionary contributions are determined annually by the Board of Trustees and are subject to the limitation imposed by the Internal Revenue Service Code 401(a)(17). The Corporation's expenses related to the Plan for the years ended December 31, 2014 and 2013 were $2,336,382 and $2,252,973, respectively. The contributions accrued as of December 31, 2014 and 2013 amounted to $1,907,563 and $1,788,624, respectively, and are included in accrued retirement liabilities in the statements of financial position.

10 Concentration of Credit Risk

The Corporation receives a significant portion of its income from assessments, based upon "net energy for load," to LSEs within the eight regions located throughout the United States, Canada and a portion of Baja California, Norte, Mexico. LSEs are assessed a proportional share of the Corporation's operating budget as well as a proportional share of the operating budget of the regional entity in whose territory the LSE is located. The Corporation issues quarterly invoices directly to LSEs or, in some circumstances, designees. With respect to LSEs located within TRE, the Corporation issues a quarterly invoice to Electric Reliability Council of Texas ("ERCOT") which then issues invoices to the LSEs in its region, collects the assessments and remits the funds to the Corporation. The Corporation then remits the regional assessments to TRE. A similar arrangement exists with respect to LSEs located within the WECC. For LSEs located within the PJM Interconnection ("PJM"), the Corporation issues invoices to PJM which issues invoices to the LSEs, collects the assessments and remits the funds to the Corporation. The Corporation then forwards the regional assessment to RFC, the regional entity. The Corporation is extending credit to the LSEs and designees and is exposed to credit risk to the extent regional assessments are paid by the Corporation to the Regional Entities prior to collecting assessments from the LSEs or designees. Based on past history, the Corporation believes that the risk of its trade accounts receivable credit exposure is limited.

11 Functional Classification

The Corporation is required to provide information about expenses reported by their functional classification, which is a method of grouping expenses according to the purpose for which costs are incurred. The Corporation groups expenses by operational programs and by administrative programs as defined by FERC.

The following table shows the functional classification of expenses for the years ended December 31, 2014 and 2013.

For the Years Ended December 31,	2014	2013
Operational Programs:		
Reliability Standards	**$ 4,435,265**	$ 5,429,867
Compliance Operations	**5,011,773**	4,683,625
Compliance Enforcement	**2,347,294**	2,437,377
Reliability Assessment and Performance Analysis	**5,289,551**	4,506,619
Event Analysis	**1,976,454**	2,283,712
Situation Awareness	**2,839,878**	3,845,999
Training, Education and Operator Certification	**1,561,112**	1,696,223
Critical Infrastructure Department	**5,783,518**	4,855,518
	29,244,845	29,738,940
Administrative Programs:		
General and Administrative	**9,331,197**	8,656,304
Legal and Regulatory	**3,946,155**	4,046,516
Information Technology	**8,484,162**	7,815,620
Human Resources	**1,075,167**	1,318,387
Finance and Accounting	**2,829,946**	2,771,726
	25,666,627	24,608,553
Total Expenses	**$ 54,911,472**	$ 54,347,493

Supplemental Schedules of Selected Expenses

For the Years Ended December 31,	2014	2013
Employee costs:		
Payroll taxes (FICA, SUI, FUI, Medicare)	$ 1,615,713	$ 1,527,728
Employee benefits - medical	2,210,021	2,053,703
Employee benefits - life / disability	198,766	173,915
Employee benefits - officers' life	-	33,328
Insurance - workers' compensation	74,343	54,219
Relocation expenses	93,176	149,215
Educational	473,415	402,958
	$ 4,665,434	$ 4,395,066
Travel and meetings:		
Meetings	$ 862,026	$ 741,766
Workshops	130,661	363,969
Travel	2,175,616	2,001,968
On-line meetings	318,627	306,603
	$ 3,486,930	$ 3,414,306
Services:		
Insurance - commercial	$ 126,127	$ 109,765
Contract and consultants	7,857,813	8,293,693
Independent trustee fees	1,010,000	931,250
Search fees	93,239	6,495
Temporary office services and agency fees	181,392	180,924
Accounting and auditing fees	162,167	143,271
Legal fees	1,054,926	845,602
	$ 10,485,664	$ 10,511,000
Office costs:		
Publications and subscriptions	$ 84,296	$ 76,993
Dues	40,862	40,862
Postage	13,854	8,022
UPS, express mail, etc.	20,215	29,509
Telephone	506,292	517,742
Office and equipment repair/services	74,528	86,810
Copying	70,426	44,720
Stationery and office forms	2,080	176
Office supplies	171,176	187,170
Bank charges	42,620	22,967
Sales and use tax	-	3,782
Card fees	82,241	81,782
Internet expenses	363,982	522,100
	$ 1,472,572	$ 1,622,635

ATTACHMENT 2

2014 ACTUAL COST-TO-BUDGET COMPARISON

AND

2014 AUDITED FINANCIAL REPORT

FOR

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
3000 BAYPORT DRIVE, SUITE 600
TAMPA, FLORIDA 33607-8410
PHONE 813.289.5644 • FAX 813.289.5646
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True Up 2014
2014 Budget Variance Explanations Based on Audited Financials

Statutory Funding

Total Funding – Favorable Variance $26k

A training program for the new software to support reliability assessments was offered for a fee and was not planned in the budget creating a favorable variance of $21k. The balance of the favorable variance is due to FRCC System Operator Subcommittee (SOS) fees collected that were more than budgeted by $5k. Because these are both pass through items, the expense for both offset the revenue.

Statutory Expenditures

Total Favorable Variance $795k

Statutory Personnel Expenses

Total Favorable Variance $709k

The favorable variance is due to open positions unfilled for portions of the 12 months (see RSD and Compliance below) and less time charged to RA (see Reliability Assessment). The Employer Discretionary Contribution and 401(k) match and fewer health premiums due to the unfilled positions accounts for a large portion of the favorable variance; additionally, health insurance is less than budgeted due to lower rates than budgeted; educational benefits and relocation expenses were under budget due to unfilled positions. These expense reductions are partially offset by the use of contract employees.

The FTE status by Program is:

Reliability Standards Development	**(0.64)**
Compliance Enforcement	**(2.62)**
Reliability Assessment	**(1.16)**
Training & Education	**(0.14)**
Situational Awareness	**(0.04)**
General Administrative	**(0.21)**
Total Statutory FTE Variance	**(4.81)**

Statutory Meeting Expenses

Total Favorable Variance $65k

Less travel by Standards and Compliance **Favorable Variance $45k**

Favorable variance in meeting expense is due to a change in venue for the SOS training seminars at a significant savings and fewer committee meetings with the creation of the Regional EntityCommittee and Compliance Forum (RECCF).

Favorable Variance $18k

Conference Calls costs were less than budgeted.

Favorable Variance $2k

Statutory Operating Expenses

Total Favorable Variance $33k

Legal fees less than budgeted	-$87k
RA Consulting Projects (Short Circuit Databank, Reliability & Security, Data Verification, MMWG and Load Forecast) were less than budgeted	-$39k
RA Consulting by committee members budgeted but not billed	-$32k
Revised allocation for RA activities after the creation of the RECCF	- $12k
SOS Training less than budgeted	-$7k
Amortization Expense for the Compliance Software additions is greater than anticipated resulting in an unfavorable variance	+$45k
Compliance Software maintenance enhancements primarily for support needed to implement NERC's changes in Business Rules	+$32k
Training program fees for the new software to support reliability assessments was not planned in the budget (See Revenue for favorable offset)	+$22k
Strategic Plan Consultant not budgeted	+$19k
Towers Watson Salary Survey Conducted, not budgeted	+$11k
Internal Auditor not budgeted	+$10k
ERAG Fees are greater than budgeted	+$3k
All Other expenses	+ $2k

Statutory Fixed Asset Expenditures

Total Unfavorable Variance $12k:

Capitalized Compliance software enhancements needed for changes to the Technical Feasibility Exception (TFE) process and scoping the Reliability Assurance Initiative (RAI) changes needed prior to implementation of RAI offset by depreciation and computers not purchased	+$12k

Non Statutory (Member Services) Funding:

Total Funding – Unfavorable Variance $56k:

Pass through billing to members for the FRCCnet Sprint MPLS network is greater than expected due to running redundant systems until full conversion to the new backup network was complete. Because this is a pass through item, it will affect the expenses by the same amount.

Total Favorable Variance $53k

Non Pension Post Retirement **Total Unfavorable Variance $109**

Non Statutory Expenditures

Total Unfavorable Variance $463k

Non Statutory Operating Expenses (Reliability Coordinator & other operations)	+$462k
Non Statutory Personnel Expenses	+$28k
Non Statutory Meeting Expenses	-$27k

Other Non-Operating Expenses

Total Favorable Variance $1,090k

Change in Non Pension, Non Cash Post Retirement Obligation of medical insurance to a limited number of grandfathered individuals from an actuarial study was not budgeted

Non Statutory Fixed Asset Expenditures

Total Favorable Variance $4k

Change in Working Capital for the Year ended 12/31/2014:

Addition to Working Capital	**$415k**	
Statutory – Addition to Working Capital		$821k
Member Services Non Statutory – Use of Working Capital		($406k)

Total Net Assets As Of 12/31/2014: Surplus	**$2,820k**	
Statutory –Surplus of		$1,922k
Member Services Non Statutory – Surplus of		$ 898k

Statements Concerning Work Completed in 2014:

Compliance Monitoring & Enforcement Program

Specifically, the Compliance Department verifies that:

1. All O&P Compliance audits (11) planned for 2014 were completed as scheduled;
2. All CIP Audits (11) planned for 2014 were completed as scheduled;
3. Conducted Risk Assessment for eleven (11) registered entities prior to each on-site/off-site audit;
4. The Technical Feasibility Exception (TFE) program related to the CIP Standards completed its fifth year in 2014. FRCC processed sixty-seven (67) requests for material changes of which sixty (60) were approved and seven (7) were not approved.
5. The annual self-certification of all registered entities in the region was completed on schedule;
6. Review, acceptance or rejection was completed for forty-five (45) Mitigation Plans and eight (8) Mitigation Plan Revisions submitted by registered entities in 2014;
7. Verification of entity completion was finalized for forty (40) Mitigation plans during 2014; and
8. Regional Compliance Evaluations were completed for eight (8) entity reliability events during 2014, of which four (4) events occurred in 2013;
9. Conducted one (1) Spot Check in 2014 as a result of an Event Compliance Evaluation.

Reliability Assessment Program

NERC Reliability Assessments (Summer, Winter and Long Term Reliability Assessment) including a Probabilistic Assessment were all completed as scheduled. In addition, the FRCC continues to support the transition to a new Bulk Electric System (BES) definition by processing Self-determined Notifications and BES Exception Requests using the NERC BESnet application.

The FRCC has actively participated in the ERO Events Analysis Process**,** developed the necessary procedures, and worked with registered entities and NERC to provide meaningful reports and Lessons Learned. FRCC continues to support the NERC Alerts process including the Facility Rating Alert efforts.

Method used to allocate indirect costs to the direct statutory program or functional areas:

The FRCC uses standard cost accounting procedures to allocate general expenses (that cannot be directly assigned) to a specific function. The system used consists of directly expensing as much as possible directly to the function (whether that function is Statutory or Member Services) that incurred the expense. This is accomplished by routing to the responsible departmental heads all invoices pertaining to their job responsibility. The departmental head assigns the functional category and returns the invoice to accounting who assigns the General Ledger Account Number (as specified in the FRCC Accounting Policy Manual – Coding of Invoices for Goods and Services). If the expense cannot be directly charged to a

particular function (example rent, payroll taxes, benefits, general office supplies, etc.), the expense is charged to holding accounts by chart of accounts line item to be allocated back to the program areas (to include General & Administrative) at the end of the month. This is done by using the monthly time accounting summarization of FTE by function. So there are two ways expenses are charged to a particular function, either by direct expense or by allocation from the results of the monthly time accounting summarization of FTE by function (including General & Administrative).

The monthly time accounting summarization of FTE by function is calculated using the time sheets that each employee is required to turn in to HR bi-weekly. Each employee allocates eight (8) hours per day to the functions they worked on that day. Their time sheet is reviewed by their departmental head and initialled bi-weekly.

Employees are categorized into 2 groups: Technical Employees – those employees who work directly on functions and have little or no administrative duties (examples would be the Compliance staff and the Engineers) and Non-Technical Staff – those employees who perform support functions that are 80% or greater nonspecific definable by function (examples would be the Accounting staff, the President, the receptionist, etc.). The time from the time sheets are entered into a macro (by employee and function worked on) for the corresponding month being accounted for. The FTE's by program are then calculated and used to allocate the total of the General & Administrative Department back to the program areas on the line "Miscellaneous".

Cash Reserves Statement

For Statutory activities, no cash reserves were used by the FRCC in 2014.

For Non-Statutory activities, there was a planned use of reserves which was used largely to complete projects budgeted in 2013 but not completed until 2014.

Statement concerning the use of Statutory Funds for Member Services Expenses:

No Statutory Funds were used to pay for Member Services Functions in 2014 and no Member Services Funds were used to pay for Statutory Functions.

Florida Reliability Coordinating Council, Inc.
Statement of Activities and Capital Expenditures Based on Audited Financials
TOTAL COMPANY
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 5,488,056	$ 5,488,057	$ (1)	
Penalty Sanctions	343,000	343,000	-	
Total ERO Funding	$ 5,831,056	$ 5,831,057	$ (1)	$ -
Membership Dues	$ 6,916,763	$ 6,916,762	1	
Testing Fees	-	-	-	
Services & Software	354,412	301,419	52,993	
Workshops	115,904	90,000	25,904	
Interest	-	-	-	
Special Assessment	-	-	-	
NonCash Post Ret Gain (Loss)	(108,814)	-	(108,814)	
Total Funding	**$ 13,109,321**	**$ 13,139,238**	**$ (29,917)**	-0.2%
Expenses				
Personnel Expenses				
Salaries	$ 5,600,880	$ 5,915,455	(314,575)	
Payroll Taxes	353,268	372,333	(19,065)	
Benefits	855,969	1,008,050	(152,081)	
Retirement Costs	735,317	931,148	(195,831)	
Total Personnel Expenses	**$ 7,545,434**	**$ 8,226,986**	**$ (681,552)**	-8.3%
Meeting Expenses				
Meetings	$ 96,181	$ 118,445	(22,264)	
Travel	163,244	230,925	(67,681)	
Conference Calls	43,969	45,879	(1,910)	
Total Meeting Expenses	**$ 303,394**	**$ 395,249**	**$ (91,855)**	-23.2%
Operating Expenses				
Consultants & Contracts	$ 4,247,959	$ 4,006,436	241,523	
Office Rent	812,686	779,924	32,762	
Office Costs	593,025	537,455	55,570	
Professional Services	53,105	196,552	(143,447)	
Miscellaneous	185,000	-	185,000	
Depreciation	192,463	134,388	58,075	
Total Operating Expenses	**$ 6,084,238**	**$ 5,654,755**	**$ 429,483**	7.6%
Total Indirect Expenses	**$ -**	**$ -**	**$ -**	
Other Non-Operating Expenses	**$ (1,090,170)**	**$ -**	**$ (1,090,170)**	
Total Expenses	**$ 12,842,896**	**$ 14,276,990**	**$ (1,434,094)**	-10.0%
Change in Assets	**$ 266,425**	**$ (1,137,752)**	**$ 1,404,177**	-100.0%
Non-Cash Expenses & Fixed Asset Expenditures				
Depreciation	$ (192,463)	$ (134,388)	$ (58,075)	
Net Non Pension Post Retir. Oblig	981,356	-	981,356	
Software CapEx	144,832	50,000	94,832	
Furniture & Fixtures CapEx	4,494	14,750	(10,256)	
Equipment & Computers CapEx	25,311	40,575	(15,264)	
Leasehold Improvements	-	3,000	(3,000)	
Increase/(Decrease) in Fixed Assets	**$ 963,530**	**$ (26,063)**	**$ 989,593**	100.0%
Total Budget	**$ 13,806,426**	**$ 14,250,927**	**$ (444,501)**	-3.1%
CHANGE IN WORKING CAPITAL	**$ (697,105)**	**$ (1,111,689)**	**$ 414,584**	100.0%
FTEs	41.96	47.24	(5.28)	
Beginning Working Capital 1/1/2014	3,542,040	2,299,266	1,242,774	
Change in Working Capital	(697,105)	(1,111,689)	414,584	
Working Capital at 12/31/2014	2,844,935	1,187,577	1,657,358	

Florida Reliability Coordinating Council, Inc.
Statement of Activities and Capital Expenditures Based on Audited Financials
TOTAL Statutory Only
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 5,488,056	$ 5,488,057	$ (1)	
Penalty Sanctions	343,000	343,000	-	
Total ERO Funding	$ 5,831,056	$ 5,831,057	$ (1)	
Membership Dues	-	-	-	
Testing Fees	-	-	-	
Services & Software	24,000	24,000	-	
Workshops	115,904	90,000	25,904	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ 5,970,960**	**$ 5,945,057**	**$ 25,903**	0.4%
Expenses				
Personnel Expenses				
Salaries	$ 3,414,283	$ 3,806,631	$ (392,348)	
Payroll Taxes	216,176	239,599	(23,423)	
Benefits	514,881	657,255	(142,374)	
Retirement Costs	451,593	602,881	(151,288)	
Total Personnel Expenses	**$ 4,596,933**	**$ 5,306,366**	**$ (709,433)**	-13.4%
Meeting Expenses				
Meetings	$ 63,639	$ 80,930	$ (17,291)	
Travel	121,969	167,209	(45,240)	
Conference Calls	16,803	18,771	(1,968)	
Total Meeting Expenses	**$ 202,411**	**$ 266,910**	**$ (64,499)**	-24.2%
Operating Expenses				
Consultants & Contracts	$ 357,495	$ 348,768	$ 8,727	
Office Rent	553,809	555,089	(1,280)	
Office Costs	124,505	118,343	6,162	
Professional Services	27,635	116,642	(89,007)	
Miscellaneous	-	-	-	
Depreciation	153,180	110,490	42,690	
Total Operating Expenses	**$ 1,216,624**	**$ 1,249,332**	**$ (32,708)**	-2.6%
Total Indirect Expenses	**$ -**	**$ -**	**$ -**	
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ 6,015,968**	**$ 6,822,608**	**$ (806,640)**	-11.8%
Change in Assets	**$ (45,008)**	**$ (877,551)**	**$ 832,543**	**-94.9%**
Fixed Asset Expenditures				
Depreciation	$ (153,180)	$ (110,490)	$ (42,690)	
Software CapEx	117,832	50,000	67,832	
Furniture & Fixtures CapEx	594	3,550	(2,956)	
Equipment & Computers CapEx	19,109	26,264	(7,155)	
Leasehold Improvements	-	3,000	(3,000)	
Increase/(Decrease) in Fixed Assets	**$ (15,645)**	**$ (27,676)**	**$ 12,031**	-43.5%
Total Budget	**$ 6,000,323**	**$ 6,794,932**	**$ (794,609)**	-11.7%
CHANGE IN WORKING CAPITAL	**$ (29,363)**	**$ (849,875)**	**$ 820,512**	**-96.5%**
FTEs	25.59	30.40	(4.81)	
Beginning Working Capital 1/1/2014	1,825,310	1,416,119	409,191	
Change in Working Capital	(29,363)	(849,875)	820,512	
Working Capital at 12/31/2014	1,795,947	566,244	1,229,703	

Florida Reliability Coordinating Council, Inc.
Financials
RELIABILITY STANDARDS
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%	
Funding					
ERO Funding					
ERO Assessments	$ 387,520	$ 387,519	$ 1	0.0%	
Penalty Sanctions	22,072	22,072	-	0.0%	
Total ERO Funding	$ 409,592	$ 409,591	$ 1	0.0%	
Membership Dues		$ -	-		
Testing Fees		-	-		
Services & Software			-		
Workshops			-		
Interest	-	-	-		
Miscellaneous	-	-	-		
Total Funding	**$ 409,592**	**$ 409,591**	**$ 1**	**0.0%**	
Expenses					
Personnel Expenses					
Salaries	141,669	$ 217,880	(76,211)	-35.0%	(1)
Payroll Taxes	8,427	13,714	(5,287)	-38.6%	
Benefits	19,964	33,809	(13,845)	-41.0%	(2)
Retirement Costs	16,629	34,595	(17,966)	-51.9%	(3)
Total Personnel Expenses	**$ 186,689**	**$ 299,998**	**$ (113,309)**	**-37.8%**	
Meeting Expenses					
Meetings	$ 1,533	$ 2,080	(547)	-26.3%	
Travel	10,548	24,913	(14,365)	-57.7%	(4)
Conference Calls	8	174	(166)	-95.4%	
Total Meeting Expenses	**$ 12,089**	**$ 27,167**	**$ (15,078)**	**-55.5%**	
Operating Expenses					
Consultants & Contracts	$ 5,030	$ 4,529	501	11.1%	
Office Rent	16,817	23,230	(6,413)	-27.6%	
Office Costs	4,769	6,324	(1,555)	-24.6%	
Professional Services	1,146	7,482	(6,336)	-84.7%	
Miscellaneous			-		
Depreciation	938	852	86	10.1%	
Total Operating Expenses	**$ 28,700**	**$ 42,417**	**$ (13,717)**	**-32.3%**	
Total Indirect Expenses	**$ 28,726**	**$ 40,017**	**$ (11,291)**	**-28.2%**	
Other Non-Operating Expense	**$ -**	**$ -**	**$ -**		
Total Expenses	**$ 256,204**	**$ 409,599**	**$ (153,395)**	**-37.5%**	
Change in Assets	**$ 153,388**	**$ (8)**	**$ 153,396**	**100.0%**	
Fixed Asset Expenditures					
Depreciation	$ (938)	$ (852)	$ (86)	10.1%	
Software CapEx			-		
Furniture & Fixtures CapEx			-		
Equipment & Computers Ca	2,383	840	1,543	183.7%	
Leasehold Improvements			-		
Increase/(Decrease) in Fixed Ass	**$ 1,445**	**$ (12)**	**$ 1,457**	**-12141.7%**	
Total Budget	**$ 257,649**	**$ 409,587**	**$ (151,938)**	-37.1%	
CHANGE IN WORKING CAPI	**$ 151,943**	**$ 4**	**$ 151,939**	**3798475.0%**	
Direct FTEs	1.09	1.73	(0.64)	-37.0%	
Indirect FTE's	0.15	0.22	(0.07)	-31.8%	
Total FTE's	1.24	1.95	(0.71)	-36.4%	

(1) Unfilled, open position for a portion of the year (-.64 FTE).
(2) Unfilled, open position for a portion of the year (-.64 FTE) and health insurance had lower rates than budgeted.
(3) Unfilled, open position for a portion of the year (-.64 FTE).
(4) FRCC Staff stopped traveling to the Standards Development Team meetings that were budgeted for.

Florida Reliability Coordinating Council, Inc.
Financials
COMPLIANCE
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%	
Funding					
ERO Funding					
ERO Assessments	$4,458,038	$ 4,458,040	$ (2)	0.0%	
Penalty Sanctions	244,311	244,311	-	0.0%	
Total ERO Funding	$ 4,702,349	$ 4,702,351	$ (2)	0.0%	
Membership Dues	-	$ -	-		
Testing Fees		-	-		
Services & Software			-		
Workshops			-		
Interest	-	-	-		
Miscellaneous	-	-	-		
Total Funding	**$ 4,702,349**	**$ 4,702,351**	**$ (2)**	**0.0%**	
Expenses					
Personnel Expenses					
Salaries	$ 2,222,713	$ 2,411,701	(188,988)	-7.8%	
Payroll Taxes	141,615	151,798	(10,183)	-6.7%	
Benefits	344,837	452,812	(107,975)	-23.8%	(1)
Retirement Costs	296,800	382,958	(86,158)	-22.5%	(2)
Total Personnel Expenses	**$ 3,005,965**	**$ 3,399,269**	**$ (393,304)**	**-11.6%**	
Meeting Expenses					
Meetings	$ 14,402	$ 4,915	9,487	193.0%	
Travel	67,379	92,966	(25,587)	-27.5%	(3)
Conference Calls	2,444	4,565	(2,121)	-46.5%	
Total Meeting Expenses	**$ 84,225**	**$ 102,446**	**$ (18,221)**	**-17.8%**	
Operating Expenses					
Consultants & Contracts	$ 178,717	$ 119,235	59,482	49.9%	(4)
Office Rent	412,115	406,366	5,749	1.4%	
Office Costs	73,149	69,926	3,223	4.6%	
Professional Services	20,919	83,069	(62,150)	-74.8%	(5)
Miscellaneous			-		
Depreciation	146,391	101,598	44,793	44.1%	(6)
Total Operating Expenses	**$ 831,291**	**$ 780,194**	**$ 51,097**	**6.5%**	
Total Indirect Expenses	**$ 450,344**	**$ 442,995**	**$ 7,349**	**1.7%**	
Other Non-Operating Expense	**$ -**	**$ -**	**$ -**		
Total Expenses	**$ 4,371,825**	**$ 4,724,904**	**$ (353,079)**	**-7.5%**	
Change in Assets	**$ 330,524**	**$ (22,553)**	**$ 353,077**	**-1565.5%**	
Fixed Asset Expenditures					
Depreciation	$ (146,391)	$ (101,598)	$ (44,793)	44.1%	
Software CapEx	117,832	50,000	67,832	135.7%	(6)
Furniture & Fixtures CapEx	594	3,550	(2,956)	-83.3%	
Equipment & Computers Ca	15,843	22,496	(6,653)	-29.6%	
Leasehold Improvements		3,000	(3,000)	-100.0%	
Increase/(Decrease) in Fixed Ass	**$ (12,122)**	**$ (22,552)**	**$ 10,430**	**-46.2%**	
Total Budget	**$ 4,359,703**	**$ 4,702,352**	**$ (342,649)**	**-7.3%**	
CHANGE IN WORKING CAPI	**$ 342,646**	**$ (1)**	**$ 342,647**	**-34264700.0%**	
Direct FTEs	16.64	19.26	(2.62)	-13.6%	
Indirect FTE's	2.33	2.39	(0.06)	-2.5%	
Total FTE's	18.97	21.65	(2.68)	-12.4%	

(1) Unfilled, open positions for a portion of the year (-2.62 FTE) and health insurance had lower rates than budgeted.
(2) Unfilled, open positions for a portion of the year (-2.62 FTE).
(3) Unfilled, open positions for a portion of the year (-2.62 FTE) and less than expected travel.
(4) Software maintenance enhancements primarily for support needed to implement NERC's changes in Business Rules.
(5) Legal fees were less than projected.
(6) Software additions that were greater than anticipated for changes to the TFE process.

Florida Reliability Coordinating Council, Inc.
Financials
RELIABILITY ASSESSMENT
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%	
Funding					
ERO Funding					
ERO Assessments	$1,300,196	$ 1,300,196	$ -	0.0%	
Penalty Sanctions	67,103	67,103	-	0.0%	
Total ERO Funding	$ 1,367,299	$ 1,367,299	$ -	0.0%	
Membership Dues	-	$ -	-		
Testing Fees		-	-		
Services & Software	24,000	24,000	-	0.0%	
Workshops			-		
Interest	-	-	-		
Miscellaneous	-	-	-		
Total Funding	**$ 1,391,299**	**$ 1,391,299**	**$ -**	**0.0%**	
Expenses					
Personnel Expenses					
Salaries	$ 551,170	$ 662,404	(111,234)	-16.8%	(1)
Payroll Taxes	34,626	41,693	(7,067)	-17.0%	
Benefits	80,475	99,378	(18,903)	-19.0%	(2)
Retirement Costs	70,926	105,185	(34,259)	-32.6%	(3)
Total Personnel Expenses	**$ 737,197**	**$ 908,660**	**$ (171,463)**	**-18.9%**	
Meeting Expenses					
Meetings	$ 6,372	$ 6,674	(302)	-4.5%	
Travel	41,348	43,265	(1,917)	-4.4%	
Conference Calls	8,558	8,543	15	0.2%	
Total Meeting Expenses	**$ 56,278**	**$ 58,482**	**$ (2,204)**	**-3.8%**	
Operating Expenses					
Consultants & Contracts	$ 118,883	$ 192,989	$ (74,106)	-38.4%	(4)
Office Rent	65,377	70,623	(5,246)	-7.4%	
Office Costs	16,535	13,480	3,055	22.7%	
Professional Services	5,051	22,829	(17,778)	-77.9%	(5)
Miscellaneous			-		
Depreciation	3,498	3,376	122	3.6%	
Total Operating Expenses	**$ 209,344**	**$ 303,297**	**$ (93,953)**	**-31.0%**	
Total Indirect Expenses	**$ 111,823**	**$ 121,676**	**$ (9,853)**	**-8.1%**	
Other Non-Operating Expense	**$ -**	**$ -**	**$ -**		
Total Expenses	**$ 1,114,642**	**$ 1,392,115**	**$ (277,473)**	**-19.9%**	
Change in Assets	**$ 276,657**	**$ (816)**	**$ 277,473**	**-34004.0%**	
Fixed Asset Expenditures					
Depreciation	$ (3,498)	$ (3,376)	$ (122)	3.6%	
Software CapEx			-		
Furniture & Fixtures CapEx			-		
Equipment & Computers Ca	731	2,562	(1,831)	-71.5%	
Leasehold Improvements			-		
Increase/(Decrease) in Fixed Ass	**$ (2,767)**	**$ (814)**	**$ (1,953)**	**239.9%**	
Total Budget	**$ 1,111,875**	**$ 1,391,301**	**$ (279,426)**	**-20.1%**	
CHANGE IN WORKING CAPI	**$ 279,424**	**$ (2)**	**$ 279,426**	**-13971300.0%**	
Direct FTEs	4.13	5.29	(1.16)	-21.9%	
Indirect FTE's	0.58	0.66	(0.08)	-12.1%	
Total FTE's	4.71	5.95	(1.24)	-20.8%	

(1) Less Staff time charged during the year (-1.16 FTE).
(2) Less Staff time charged during the year (-1.16 FTE) and health insurance had lower rates than budgeted.
(3) Less Staff time charged during the year (-1.16 FTE).
(4) Consulting projects (Short Circuit Databank, Reliability & Security, Data Verification, MMWG and Load Forecast) were less than budgeted and consulting by committee members budgeted but not billed.
(5) Legal fees were less than projected.

Florida Reliability Coordinating Council, Inc.
Financials
TRAINING AND EDUCATION
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%	
Funding					
ERO Funding					
ERO Assessments	$ 173,812	$ 173,812	$ -	0.0%	
Penalty Sanctions	8,499	8,499	-	0.0%	
Total ERO Funding	$ 182,311	$ 182,311	$ -	0.0%	
Membership Dues	-	$ -	-		
Testing Fees		-	-		
Services & Software			-		
Workshops	115,904	90,000	25,904	28.8%	(1)
Interest	-	-	-		
Miscellaneous	-	-	-		
Total Funding	**$ 298,215**	**$ 272,311**	**$ 25,904**	**9.5%**	
Expenses					
Personnel Expenses					
Salaries	$ 72,421	$ 83,896	(11,475)	-13.7%	(2)
Payroll Taxes	4,621	5,281	(660)	-12.5%	
Benefits	20,781	11,616	9,165	78.9%	
Retirement Costs	10,458	13,325	(2,867)	-21.5%	
Total Personnel Expenses	**$ 108,281**	**$ 114,118**	**$ (5,837)**	**-5.1%**	
Meeting Expenses					
Meetings	$ 41,298	$ 67,248	(25,950)	-38.6%	(3)
Travel	2,634	5,996	(3,362)	-56.1%	
Conference Calls	5,793	5,481	312	5.7%	
Total Meeting Expenses	**$ 49,725**	**$ 78,725**	**$ (29,000)**	**-36.8%**	
Operating Expenses					
Consultants & Contracts	$ 51,695	$ 29,259	22,436	76.7%	(4)
Office Rent	8,732	8,945	(213)	-2.4%	
Office Costs	23,779	22,610	1,169	5.2%	
Professional Services	449	2,916	(2,467)	-84.6%	
Miscellaneous			-		
Depreciation	725	590	135	22.9%	
Total Operating Expenses	**$ 85,380**	**$ 64,320**	**$ 21,060**	**32.7%**	
Total Indirect Expenses	**$ 15,449**	**$ 15,412**	**$ 37**	**0.2%**	
Other Non-Operating Expense	**$ -**	**$ -**	**$ -**		
Total Expenses	**$ 258,835**	**$ 272,575**	**$ (13,740)**	**-5.0%**	
Change in Assets	**$ 39,380**	**$ (264)**	**$ 39,644**	**-15016.7%**	
Fixed Asset Expenditures					
Depreciation	$ (725)	$ (590)	$ (135)	22.9%	
Software CapEx			-		
Furniture & Fixtures CapEx			-		
Equipment & Computers Ca	142	327	(185)	-56.6%	
Leasehold Improvements			-		
Increase/(Decrease) in Fixed Ass	**$ (583)**	**$ (263)**	**$ (320)**	**121.7%**	
Total Budget	**$ 258,252**	**$ 272,312**	**$ (14,060)**	**-5.2%**	
CHANGE IN WORKING CAPI	**$ 39,963**	**$ (1)**	**$ 39,964**	**-3996400.0%**	
Direct FTEs	0.54	0.68	(0.14)	-20.6%	
Indirect FTE's	0.08	0.08	-	0.0%	
Total FTE's	0.62	0.76	(0.14)	-18.4%	

(1) A training program for the new software to support reliability assessments was offered for a fee and was not planned in the budget, and SOS fees collected that were more than budgeted.
(2) Less staff time charged to T&E due to unfilled, open positions for a portion of the year (-.14 FTE)
(3) There was a change in venue for the SOS training seminars at a significant savings.
(4) Training program fees for the new software to support reliability assessments was not planned in the budget.

Florida Reliability Coordinating Council, Inc.
Financials
SITUATIONAL AWARENESS
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 18,365	$ 18,365	$ -	0.0%
Penalty Sanctions	1,015	1,015	-	0.0%
Total ERO Funding	$ 19,380	$ 19,380	$ -	0.0%
Membership Dues	-	$ -	-	
Testing Fees		-	-	
Services & Software			-	
Workshops			-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ 19,380**	**$ 19,380**	**$ -**	**0.0%**
Expenses				
Personnel Expenses				
Salaries	$ 6,362	$ 10,017	(3,655)	-36.5%
Payroll Taxes	446	631	(185)	-29.3%
Benefits	789	1,387	(598)	-43.1%
Retirement Costs	879	1,591	(712)	-44.8%
Total Personnel Expenses	**$ 8,476**	**$ 13,626**	**$ (5,150)**	**-37.8%**
Meeting Expenses				
Meetings	$ 34	$ 13	21	161.5%
Travel	60	69	(9)	-13.0%
Conference Calls	-	8	(8)	-100.0%
Total Meeting Expenses	**$ 94**	**$ 90**	**$ 4**	**4.4%**
Operating Expenses				
Consultants & Contracts	$ 217	$ 209	8	3.8%
Office Rent	738	1,068	(330)	-30.9%
Office Costs	1,996	2,162	(166)	-7.7%
Professional Services	70	346	(276)	-79.8%
Miscellaneous			-	
Depreciation	1,628	2,431	(803)	-33.0%
Total Operating Expenses	**$ 4,649**	**$ 6,216**	**$ (1,567)**	**-25.2%**
Total Indirect Expenses	**$ 1,243**	**$ 1,840**	**$ (597)**	**-32.4%**
Other Non-Operating Expense	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ 14,462**	**$ 21,772**	**$ (7,310)**	**-33.6%**
Change in Assets	**$ 4,918**	**$ (2,392)**	**$ 7,310**	**-305.6%**
Fixed Asset Expenditures				
Depreciation	$ (1,628)	$ (2,431)	$ 803	-33.0%
Software CapEx			-	
Furniture & Fixtures CapEx			-	
Equipment & Computers Ca	10	39	(29)	-74.4%
Leasehold Improvements			-	
Increase/(Decrease) in Fixed Ass	**$ (1,618)**	**$ (2,392)**	**$ 774**	**-32.4%**
Total Budget	**$ 12,844**	**$ 19,380**	**$ (6,536)**	**-33.7%**
CHANGE IN WORKING CAPI	**$ 6,536**	**$ -**	**$ 6,536**	**100.0%**
Direct FTEs	0.04	0.08	(0.04)	-50.0%
Indirect FTE's	0.01	0.01	-	0.0%
Total FTE's	0.05	0.09	(0.04)	-44.4%

Florida Reliability Coordinating Council, Inc.
Financials
GENERAL ADMINISTRATIVE
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%	
Funding					
ERO Funding					
ERO Assessments	$ (849,875)	$ (849,875)	$ -	0.0%	
Penalty Sanctions		-	-		
Total ERO Funding	$ (849,875)	$ (849,875)	$ -	0.0%	
Membership Dues	-	$ -	-		
Testing Fees		-	-		
Services & Software			-		
Workshops			-		
Interest	-	-	-		
Miscellaneous	-	-	-		
Total Funding	**$ (849,875)**	**$ (849,875)**	**$ -**	**0.0%**	
Expenses					
Personnel Expenses					
Salaries	$ 419,948	$ 420,733	$ (785)	-0.2%	
Payroll Taxes	26,441	26,482	(41)	-0.2%	
Benefits	48,035	58,253	(10,218)	-17.5%	(1)
Retirement Costs	55,901	65,227	(9,326)	-14.3%	
Total Personnel Expenses	**$ 550,325**	**$ 570,695**	**$ (20,370)**	**-3.6%**	
Meeting Expenses					
Meetings			$ -		
Travel			-		
Conference Calls		-	-		
Total Meeting Expenses	**$ -**	**$ -**	**$ -**		
Operating Expenses					
Consultants & Contracts	$ 2,953	$ 2,547	$ 406	15.9%	
Office Rent	50,030	44,857	5,173	11.5%	
Office Costs	4,277	3,841	436	11.4%	
Professional Services		-	-		
Miscellaneous			-		
Depreciation		1,643	(1,643)	-100.0%	
Total Operating Expenses	**$ 57,260**	**$ 52,888**	**$ 4,372**	**8.3%**	
Total Indirect Expenses	**$ (607,585)**	**$ (621,940)**	**$ 14,355**	**-2.3%**	
Other Non-Operating Expense	**$ -**	**$ -**	**$ -**		
Total Expenses	**$ -**	**$ 1,643**	**$ (1,643)**	**-100.0%**	
Change in Assets	**$ (849,875)**	**$ (851,518)**	**$ 1,643**	**-0.2%**	
Fixed Asset Expenditures					
Depreciation	$ -	$ (1,643)	$ 1,643	-100.0%	
Software CapEx			-		
Furniture & Fixtures CapEx			-		
Equipment & Computers CapEx			-		
Leasehold Improvements			-		
Increase/(Decrease) in Fixed Ass	**$ -**	**$ (1,643)**	**$ 1,643**	**-100.0%**	
Total Budget	**$ -**	**$ -**	**$ -**		
CHANGE IN WORKING CAPIT	**$ (849,875)**	**$ (849,875)**	**$ -**	**0.0%**	
FTEs	3.15	3.36	(0.21)	-6.3%	

(1) Health insurance had lower rates than budgeted.

Florida Reliability Coordinating Council, Inc.
Statement of Activities and Capital Expenditures Based on Audited Financials
TOTAL MEMBER SERVICES - NON STATUTORY
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	$ -	$ -	$ -	
Membership Dues	6,916,763	6,916,762	1	
Testing Fees	-	-	-	
Services & Software	330,412	277,419	52,993	
Workshops	-	-	-	
Special Assessment	-	-	-	
Non Cash Postretirement	(108,814)	-	(108,814)	
Total Funding	**$ 7,138,361**	**$ 7,194,181**	**$ (55,820)**	-0.8%
Expenses				
Personnel Expenses				
Salaries	$ 2,186,597	$ 2,108,824	77,773	
Payroll Taxes	137,092	132,734	4,358	
Benefits	341,088	350,795	(9,707)	
Retirement Costs	283,724	328,267	(44,543)	
Total Personnel Expenses	**$ 2,948,501**	**$ 2,920,620**	**$ 27,881**	1.0%
Meeting Expenses				
Meetings	$ 32,542	$ 37,515	(4,973)	
Travel	41,275	63,716	(22,441)	
Conference Calls	27,166	27,108	58	
Total Meeting Expenses	**$ 100,983**	**$ 128,339**	**$ (27,356)**	-21.3%
Operating Expenses				
Consultants & Contracts	$ 3,890,464	$ 3,657,668	232,796	
Office Rent	258,877	224,835	34,042	
Office Costs	468,520	419,112	49,408	
Professional Services	25,470	79,910	(54,440)	
Miscellaneous	185,000	-	185,000	
Depreciation	39,283	23,898	15,385	
Total Operating Expenses	**$ 4,867,614**	**$ 4,405,423**	**$ 462,191**	10.5%
Total Indirect Expenses				
Other Non-Operating Expenses	**$ (1,090,170)**	**$ -**	**$ (1,090,170)**	
Total Expenses	**$ 6,826,928**	**$ 7,454,382**	**$ (627,454)**	-8.4%
Change in Assets	**$ 311,433**	**$ (260,201)**	**$ 571,634**	
Non-Cash Expenses & Fixed Asset Expenditures				
Depreciation	$ (39,283)	$ (23,898)	$ (15,385)	
Net Non Pension Post Retir. Oblig	981,356	-	981,356	
Software CapEx	27,000	-	27,000	
Furniture & Fixtures CapEx	3,900	11,200	(7,300)	
Equipment & Computers CapEx	6,202	14,311	(8,109)	
Leasehold Improvements	-	-	-	
Increase/(Decrease) in Fixed Assets	**$ 979,175**	**$ 1,613**	**$ 977,562**	60605.2%
Total Budget	**$ 7,806,103**	**$ 7,455,995**	**$ 350,108**	4.7%
CHANGE IN WORKING CAPITAL	**$ (667,742)**	**$ (261,814)**	**$ (405,928)**	
FTEs	16.37	16.84	(0.47)	
Beginning Working Capital 1/1/2014	1,716,730	883,147	833,583	
Change in Working Capital	(667,742)	(261,814)	(405,928)	
Working Capital at 12/31/2014	1,048,988	621,333	427,655	

Florida Reliability Coordinating Council, Inc.

FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES

December 31, 2014

Florida Reliability Coordinating Council, Inc.
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December 31, 2014

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REPORT

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INDEPENDENT AUDITORS' REPORT

To the Corporate Compliance, Finance & Audit Committee
Florida Reliability Coordinating Council, Inc.

Report on the Financial Statements

We have audited the accompanying financial statements of Florida Reliability Coordinating Council, Inc., (a nonprofit organization) which comprise the statement of financial position as of December 31, 2014, and the related statements of activities and cash flows for the year then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

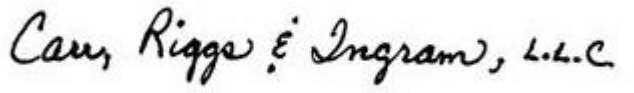
We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the statement of financial position of Florida Reliability Coordinating Council as of December 31, 2014 and the changes in its net assets and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matter

Our audit was conducted for the purpose of forming an opinion on the financial statements as a whole. The statutory and non-statutory schedules on Pages 19 to 27 inclusive are presented for purposes of additional analysis and are not a required part of the financial statements. Such information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the financial statements. The information has been subjected to the auditing procedures applied in the audit of the financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the financial statements or to the financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the information is fairly stated in all material respects in relation to the financial statements as a whole.



CARR, RIGGS & INGRAM, LLC

Clearwater, Florida
January 29, 2015

FINANCIAL STATEMENTS

Florida Reliability Coordinating Council, Inc.
Statement of Financial Position
December 31, 2014

ASSETS		
Current assets:		
Cash	$	5,598,797
Compliance penalty money		256,000
Member receivables		3,240,982
Related party receivable		3,174
Prepaid expenses		66,724
Total current assets		9,165,677
Property and equipment - at cost		
Equipment and computers		585,463
Software		1,055,796
Furniture and fixtures		322,226
Leasehold improvements		126,636
Total		2,090,121
Less accumulated depreciation and amortization		(1,689,494)
Total property and equipment, net		400,627
Other assets		
Deposits		150,000
Deferred compensation plans		143,187
Total other assets		293,187
Total assets	$	9,859,491
LIABILITIES AND NET ASSETS		
Current liabilities:		
Accounts payable	$	575,351
Current portion of accrued postretirement benefit obligation		17,908
Deferred compensation liability		143,187
Deferred revenue		3,493,661
Compliance penalty assessment		256,000
Accrued expenses		2,145,443
Total current liabilities		6,631,550
Long-term liabilities:		
Accrued postretirement benefit obligation		407,558
Net assets:		
Unrestricted statutory - FERC designated		2,553,961
Unrestricted member services - board designated		266,422
Total net assets		2,820,383
Total liabilities and net assets	$	9,859,491

The accompanying notes are an integral part of these financial statements.

Florida Reliability Coordinating Council, Inc.
Statement of Activities
December 31, 2014

Revenues:	
Nonstatutory member assessments	$ 6,916,763
Statutory member assessments	5,488,056
Services and software	354,412
Training and education fees	115,904
Postretirement benefit loss	(108,814)
Gain on deferred compensation plans	17,237
Penalty and sanctions realized	343,000
Total revenue	13,126,558
Expenses:	
Salaries	5,600,880
Payroll taxes	353,268
Employee benefits	855,969
Retirement and deferred compensation plans	735,317
Meetings	96,181
Travel	163,244
Conference calls	43,969
Contracts & consultants	4,247,959
Facilities rental	812,686
Office costs	593,028
Legal and accounting	53,105
Penalty sanctions	185,000
Deferred compensation plans	17,237
Depreciation and amortization	192,463
Total expenses	13,950,306
Decrease in net assets before change in accumulated post retirement obligation	(823,748)
Net periodic change in postretirement obligation	1,090,170
Increase in net assets	266,422
Net assets - beginning of year	2,553,961
Net assets - end of year	$ 2,820,383

The accompanying notes are an integral part of these financial statements.

Florida Reliability Coordinating Council, Inc.
Statement of Cash Flows
December 31, 2014

Cash flows from operating activities:	
Cash received from members	$ 12,721,244
Cash paid to suppliers and employees	(13,250,443)
Net cash used by operating activities	(529,199)
Cash flows from investing activities	
Purchases of software and equipment	(174,636)
Net cash used by investing activities	(174,636)
Net decrease in cash	(703,835)
Cash at beginning of year	$ 6,558,632
Cash at end of year	$ 5,854,797
Reconciliation of increase in net assets to net cash used by operating activities	
Increase in net assets	$ 266,422
Adjustments to reconcile increase in net assets to net cash used by operating activities:	
Depreciation and amortization	192,463
Increase in receivables, prepaid expenses, and other assets	(437,284)
Increase in accounts payable and accrued expenses	48,850
Change in postretirement benefit obligation	(981,356)
Increase in deferred income	381,706
Net cash used by operating activities	$ (529,199)

The accompanying notes are an integral part of these financial statements.

NOTE 1: GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Florida Reliability Coordinating Council, Inc. (the "Company") is a group of electric utilities and energy marketers primarily doing business in the State of Florida. The purpose of the Company is to ensure and enhance the reliability and adequacy of the bulk power supply in Florida (which is defined as the general area encompassed by Peninsula Florida) now and into the future. The Company serves as a Regional Entity with delegated authority from the North American Electric Reliability Corporation ("NERC") for the purpose of proposing and enforcing reliability standards within the FRCC region.

On May 2, 2007, the Company entered into a Delegation Agreement with North American Electric Reliability Corporation ("NERC"), an organization certified by the Federal Energy Regulatory Commission pursuant to Section 215(c) of the Federal Power Act. The Company is required by federal law to assess the reliability of the Bulk Power System. The Federal Energy Regulatory Commission ("FERC") empowered the Company through a Delegation Agreement with NERC to monitor, enforce and implement electric reliability standards under Section 215 of the Federal Power Act. The Company is responsible for establishing the process for development, revision, withdrawals and approval of the Company's Regional Reliability Standards for the region. The Company monitors and enforces compliance with NERC and FERC reliability standards through on-site audits, self-certifications, periodic spot checks, self-reports, event investigation, periodic data submittal, exception reporting and through complaints. The initial term of the agreement is for three years and is renewable for five more years upon a successful compliance audit conducted by NERC.

The Company's source of revenue is split into two parts. The statutory functions, defined as those functions being performed for Reliability Standards and Compliance, are funded by NERC. The member services functions are paid by its members who are assessed for costs and expenses of establishing, developing, operating and maintaining the Company.

A summary of the Company's significant accounting policies consistently applied in preparation of the accompanying financial statements follows:

The financial statements have been prepared on the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America; consequently, revenues and gains are recognized when earned, and expenses and losses are recognized when incurred.

Concentration of Credit Risk

The Company places its cash with high credit quality institutions. At times, these balances may be in excess of the FDIC insurance limit.

NOTE 1: GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Use of Estimates

Management uses estimates and assumptions in preparing these financial statements in accordance with accounting principles generally accepted in the United States of America. Those estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses. Actual results could vary from the estimates that are used.

Income Taxes

The Company has been approved for tax-exempt status under Section 501(c) (6) of the Internal Revenue Code and is exempt from federal and state income taxes. Accordingly, no provision for income taxes is included in the financial statements. Tax years after 2010 remain subject to examination by taxing authorities.

The Company follows Accounting Standard Codification (ASC) 740, "Accounting for Income Taxes" with respect to accounting for uncertainty in income taxes. A tax position is recognized as a benefit only if it is "more likely than not" that the tax position would be sustained in a tax examination, with a tax examination being presumed to occur. The amount recognized is the largest amount of tax benefit that is greater than 50% likely of being realized on examination. For tax positions not meeting the "more likely than not" test, no tax benefit is recorded.

Due to its tax-exempt status, the Company is not subject to U.S. federal income tax or state income tax. The Company's Form 990 has not been subject to examination by the Internal Revenue Service or the State of Florida for the last three years. The Company has not recognized liability for unrecognized tax benefits as it has no known tax positions that would subject the Company to any material income tax exposure. A reconciliation of the beginning and ending amount of unrecognized tax benefits and interest accrued related to unrecognized tax benefits are not included nor is there any interest accrued related to unrecognized tax benefits or interest expense and penalties in operating expenses as there are no unrecognized tax benefits.

Member, Related Party, and Other Receivables

Management evaluates all receivables annually for collectability. As of December 31, 2014 management considers all receivables to be fully collectible, therefore; no allowance for doubtful accounts is considered necessary and no late fees are assessed. If amounts are deemed to be uncollectible, they will be charged to an allowance for doubtful accounts when that determination is made.

NOTE 1: GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Property and Equipment

Property and equipment with a cost over $500 are capitalized and are stated at cost, less accumulated depreciation and amortization. Depreciation and amortization are provided for in amounts sufficient to relate the cost of depreciable assets to operations over their estimated service lives, principally on a straight-line basis. The estimated lives used in determining depreciation are:

Equipment	5 years
Software	3 years
Furniture and fixtures	7 years
Leasehold improvements	5 years

Leasehold improvements are amortized over the lives of the respective leases or the service lives of the improvements, whichever is shorter.

Line of Credit

The Company secured a line of credit from Bank of America, N.A. for two (2) years in the amount of $1,500,000. The line of credit is intended to be used for short term needs that arise between budget funding periods as a bridge between budget years. The covenants call for a funded debt to total unrestricted and temporarily restricted net assets not exceeding 2.0:1.0 and an out of debt period of 30 days each line year. The total charges and fees for 2 year term were paid in 2013 and none were due or paid in 2014. As of December 31, 2014, the company has not drawn on the line of credit and is in full compliance with all covenants.

Postretirement Benefits Other Than Pensions

The Company sponsors a postretirement health care or benefit plan for employees hired before October 1, 2003 (and the spouse of one retired employee) if the retiree meets certain conditions specified in their individual plan at the time of retirement. The breakdown on the plan is as follows: one retiree spouse remains on the original health care retirement plan granted in 2006 which provides for health insurance for life, one retiree converted effective November 1, 2014 to receiving an annual amount funded to a Health Retirement Account (HRA), in the amount of $4,200 per year, in lieu of coverage on a health care policy, and three (3) current employees converted to a plan which provides health care coverage if they retire at age 60 or later from active employment from the FRCC until age 65 at which time they stop being provided with health care coverage and will then begin to receive an annual amount of $4,200 funded to an HRA. These plans cease upon the death of the employee and all fund balances in each of the HRA accounts revert back to the company. The individual plans are noncontributory for retirees (see Note 6).

NOTE 1: GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Date of Management's Review

Management has evaluated events and transactions for potential recognition or disclosure through January 29, 2015, which is the date the financial statements were available to be issued.

NOTE 2: FAIR VALUE MEASUREMENTS

Financial Accounting Standards Board ASC 820 establishes a framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under FASB ASC 820 are described below:

Level 1 Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets that the Organization has the ability to access.

Level 2 Inputs to the valuation methodology include:

- Quoted prices for similar assets or liabilities in active markets;
- Quoted prices for identical or similar assets or liabilities in inactive market;
- Inputs other than quoted prices that are observable for that asset or liability'
- Inputs that are derived principally from or corroborated by observable market data by correlation or other means

If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.

Level 3 Inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The asset's or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

The following is a description of the valuation methodologies used for the Organization's securities invested in the deferred compensation plans measured at fair value as of December 31, 2014:

Cash and cash equivalents: The carrying amounts reported in the Statements of Financial Position approximate the fair value because of the short maturities of those instruments.

NOTE 2: FAIR VALUE MEASUREMENTS (Continued)

Mutual funds: Measured at net asset value within the active market on which the individual securities are traded.

The methods described above may produce a fair value calculation that may not be indicative of the net realizable value or reflective of future fair values. Furthermore, while the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

The fair values of the Company's securities invested in the deferred compensation plans, classified by level, are as follows:

	December 31, 2014			
	Fair Value	Level 1	Level 2	Level 3
Cash & equivalents	$ 1,968	$ 1,968		
Mutual funds - fixed income	19,409	19,409		
Mutual funds - equities	121,731	121,731		
Total	$ 143,108	$ 143,108	$ -	$ -

The fair value and cost of the Company's securities invested in the deferred compensation plans, as of December 31, 2014 are as follows:

	Cost Value	Market Value
Cash & equivalents	$ 1,968	$ 1,968
Mutual funds - fixed income	20,426	19,409
Mutual funds - equities	96,638	121,731
Total	$ 119,032	$ 143,108

NOTE 3: DEFERRED REVENUE

The contracts with the members of FRCC have a provision in them that provides that they have 30 days from the date of invoice for a new budgetary year (January through December) to withdraw from membership. Therefore, the Company made a decision to invoice all members on December 1 for the first quarterly installment of the 2015 budget, thus at December 31, 2014 it would be known whether all members are continuing with their membership.

NOTE 4: COMMITMENTS

In December 2003, the Company entered into an agreement with Sprint Communications Company L.P. ("Sprint") to provide certain telecommunication services that are passed through to certain members beginning in 2004 for the Company's network. The initial term of the agreement is 36 months and has been renewed for an additional 12-month period each year thereafter. The agreement calls for the Company to make a minimum service commitment of $96,000 for each contract year of the term.

In December 2006, the Company entered into an agreement with Open Access Technology International, Inc. to provide the Florida Transaction Management System ("FTMS") services for the Company's customers. The initial term of the agreement was 36 months at $3,750 per month and has been renewed for an additional 12-month period each year thereafter. In 2014, the Company renewed this contract for 36 months at an annual cost of $61,000. In addition, several enhancements to the FTMS service were agreed upon of which $27,000 was paid for in 2014 for the completion of the enhancements. The Company also has the option to purchase the system for $100,000; however, at this time, the Company has no intention of doing so.

In November 2007, the Company entered into an agreement to purchase Compliance Tracking System software from Guidance Solutions, Inc. In 2008, the Company entered into an agreement with several of the other regional entities to form a consortium and share the cost of future enhancements and program modules to add to the Compliance Tracking System originally purchased from Guidance Solutions, Inc. In June of 2011, the consortium broke up with certain member regions deciding to change software and vendors and go in a different direction for their Compliance Tracking System. The Company decided to remain with Guidance and has agreed to share costs of software enhancements with two other regions that remain with Guidance. The cost of enhancements added or in progress for 2014 was $117,831. The Company is obligated for enhancements in progress as of December 31, 2014 from this regional agreement of approximately $184,000 for enhancements to be completed in 2015. The Company is also obligated for enhancements of their own system for $70,000 to be completed in 2015.

In May of 2013, the Company entered into an agreement with other Eastern Interconnection Reliability Coordinators and created the Interchange Distribution Calculator (IDC) Tools Member Association to manage the IDC Application contract that in prior years was managed by NERC. This tool is used to manage transmission congestion across the Eastern Interconnection. The agreement calls for the Company to make a minimum service commitment of $118,600 for each contract year of the term.

In May of 2013 the Company entered into agreements with Cisco Systems Capital Corporation to provide WebEx online presentation and audio conferencing services. The initial term of the agreement is for 36 months and call for the Company to make a total commitment of $130,500 over the 36-month term.

NOTE 4: COMMITMENTS (Continued)

In July 2013, the company entered into an agreement with TW Telecom Holdings, Inc. (TW Telecom) to provide required redundant telecommunications for the FRCCnet wide area network that provides data to the FRCC reliability Coordinator. The initial term of the agreement is 36 months and calls for the Company to make a minimum service commitment of $68,400 for each contract year of the term.

NOTE 5: OPERATING LEASES

The Company leases its facilities and has operating leases that expire September 30, 2020 at its current location on Bayport Drive. The Bayport Plaza lease required a $150,000 deposit. For all leases, rental payments escalate based on the schedules set forth in the lease agreement. Minimum future rental payments are:

Year Ended December 31,		
2015	$	766,199
2016		787,166
2017		808,832
2018		831,070
2019		854,008
2020 and thereafter		644,842
	$	4,692,117

Rent expense charged to operations during the year ended December 31, 2014 was $812,686, including the effects of lease payment escalations over the term of the leases.

For all leases, the future expense to be recognized including the effects of rent abatements and rent escalations are as follows:

Year Ended December 31,		
2015	$	750,602
2016		750,602
2017		750,602
2018		750,602
2019		750,602
2020 and thereafter		562,952
	$	4,315,962

NOTE 6: POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

The Company adheres to ASC 715-30, *Defined Benefit Plans - Other Post Retirement,* which requires companies to report the funded status (defined as the difference between the fair value of plan assets and the plan's benefit obligation) of their postretirement plan. The current year effect is a $1,090,170 increase to unrestricted net assets.

This substantial change is the result of the conversion of the original plan (by four of the five eligible persons) to other appropriate plans. The census for this benefit is as follows: one retiree spouse remains on the original health care retirement plan granted in 2006 which provides for health insurance for life, one retiree converted effective November 1, 2014 to receiving an annual amount funded to a Health Retirement Account (HRA), in the amount of $4,200 per year, in lieu of coverage on a health care policy, and three (3) current employees converted to a plan which provides health care coverage if they retire at age 60 or later, from active employment from the FRCC, until age 65 at which time they stop being provided with health care coverage and will then begin to receive an annual amount of $4,200 funded to an HRA. These plans cease upon the death of the employee and all fund balances in each of the HRA accounts revert back to the company.

The following table sets forth the Plan's funded status reconciled with the amount shown in the Company's statement of financial position at December 31, 2014:

Accumulated postretirement benefit oligation:	
Plan assets at fair value	-0-
Funded status	-0-
Accrued postretirement benefit obligation:	
Current portion	$ 17,908
Long-term portion	407,558
	$ 425,466

Since the plan is non-contributory, the entire balance of the accumulated benefit obligation is recorded as a liability in the statement of financial position as of December 31, 2014.

NOTE 6: POSTRETIREMENT BENEFITS OTHER THAN PENSIONS (Continued)

Benefits expected to be paid in each of the next five years are as follows:

Year Ended December 31,	
2015	$ 17,908
2016	18,863
2017	23,921
2018	24,670
2019	25,275
2020 and thereafter	116,501
	$ 227,138

The following provides the components of net periodic postretirement benefit cost for the year ended December 31, 2014.

Service Cost	$ (39,983)
Interest Cost	(66,042)
Amortization of unrecognized net obligation	(10,664)
Amortization of unrecog prior service cost/(asset)	
Recognition of net actuarial loss	(25,039)
Net periodic postretirement benefit cost	(141,728)
Benefits paid during 2014	32,914
Net postretirement benefit loss	$ (108,814)
Items not yet recognized as a component of net periodic postretirement benefit costs	
Unrecognized net gain	$ 300,690
Net unrecognized prior service cost	344,780
Transitional effect of ASC 715-30	645,470
Postretirement effect of ASC 715-30 as of December 31 2013	$ (444,700)
Net periodic change in postretirement obligation	1,090,170
Postretirement obligation recognized as a component of net periodic benefit cost as of December 31, 2014	$ 645,470

NOTE 6: POSTRETIREMENT BENEFITS OTHER THAN PENSIONS (Continued)

Amounts included in unrestricted net assets and expected to be recognized as components of net periodic benefit gain (cost) next year include amortization of unrecognized net obligation and net actuarial loss of approximately ($11,000) and ($25,000), respectively. For measurement purposes, an 8% annual rate increase in the per capita cost of covered health care benefits was assumed for 2016; the rate was assumed to decrease to 7% for 2017; 6% for 2018 and remain at 5% thereafter. The health care cost trend rate assumption has a significant effect on the amounts reported. To illustrate, if assumed health care cost trend rates were increased by one percentage point in each year, the accumulated postretirement benefit obligation at December 31, 2014 would be increased $62,079 and the aggregate of the service and interest cost components of net periodic postretirement benefit cost for the year ended December 31, 2014 would be increased by $980.

The weighted average discount rate used in estimating the accumulated postretirement benefit obligation was 4.0%. Mortality was based on the RP-2000 Combined Mortality Tables for Healthy Males and Females. The measurement date of the accumulated postretirement benefit obligation was December 31, 2014.

Glossary

Accumulated postretirement benefit obligation - The actuarial present value of benefits attributed to employee service rendered to a particular date.

Net periodic postretirement benefit gain - The amount recognized in the financial statements as the gain of the postretirement benefit plan for a period.

In December of 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) was signed into law. The Act includes a special subsidy for employers that sponsor retiree health benefit plans with prescription drug benefits that are as favorable as the Medicare Part D benefit. The Company has not determined whether its plan is actuarially equivalent to the Medicare Part D benefit due to the cost of obtaining such an actuarial computation.

NOTE 7: RETIREMENT PLAN

Effective January 1, 2001, the Company adopted a 401(k) Plan (“Plan”) intended to benefit substantially all employees with 6 months of service and 21 years of age. On September 30, 2007, the Plan was amended to enable employees with one hour of service to be eligible to enter the Plan. Participants can contribute any amount of their compensation for the Plan year, not to exceed the limits determined by the Internal Revenue Code. The Company may make matching contributions with prescribed limits. The Company may also make additional non-elective discretionary contributions to the Plan. The Company made matching contributions to the Plan of $297,473 and a discretionary contribution to the Plan of $409,491 (net of forfeitures) for the year ending December 31, 2014.

NOTE 7: RETIREMENT PLAN (Continued)

Deferred Compensation – The Company implemented an executive deferred compensation plan subject to Section 457(f) of the Internal Revenue Code in 2004. For the year ended December 31, 2014, the Company contributed $8,492 to benefit the participant in this Plan.

In 2013, the Company adopted a Nonqualified 457(b) Retirement Plan ("Retirement Plan"), to be effective January 1, 2014, intended to benefit key managerial employees of the Company. The Company funded the account in 2014 $16,775 for the 2013 liability and expensed $28,736 in 2014 that will be funded in 2015.

NOTE 8: RELATED PARTIES

Various members of the Company are founding members of Florida Electric Power Coordinating Group, Inc. ("FCG") and the organizations, excluding the Board of Directors, were under common management until November 30, 2014. Effective November 30, 2014, The President & CEO of the FRCC resigned from management of the FCG. FCG is a nonprofit organization operating under Section 501(c)(6) of the Internal Revenue Code and is exempt from federal and state income taxes.

The Company has decided to continue providing FCG with administrative and accounting services, including the use of office space. FCG reimbursed the Company approximately 1.97% of the Company's administrative expenses in 2014. The service agreement with FCG is a one-year agreement that will automatically renew unless canceled in advance by either party. The original agreement was renewed for an additional year in February 2014. Currently the company is in the process of negotiating a new contract for 2015. At December 31, 2014, the Company had billed and collected a total of $192,217 from FCG relating to the service agreement and has a receivable from FCG in the amount of $3,174.

The Company is purchasing the services from Florida Power and Light ("FPL"), a member of the Company, to fulfill the responsibilities of reliability coordinator, operations planning coordinator, state capacity emergency coordinator as well as various other services. The Company paid FPL $3,219,144 for these services and at December 31, 2014 had $651,213 of accrued expenses recorded on the books.

NOTE 9: CONCENTRATIONS

Two members make up approximately 54.9% of the member services assessments and dues. The same two members comprise 67.1% of the statutory assessment that NERC bills directly in order to fund the Company for its statutory function.

NOTE 10: CONTINGENCIES

As part of the Company's Delegation Agreement with NERC, the Company has the authority to fine entities within its region for violation of reliability standards. During 2013, six (6) notices of penalty were filed with FERC with settlement agreements addressing alleged violations of reliability standards for the entities within the FRCC region. The penalties totaling $111,000 as of December 31, 2014, were approved by FERC and paid by the entities. The Delegation Agreement Rules of Procedures from NERC stipulate that any penalty monies collected by June 30 of each year, which is between budget submissions, are to be held until they can be accounted for in a budget submission. At year-end December 31, 2014, a total of $256,000 penalty assessment is being held for future use of which $175,000 was accounted for in the 2015 budget submission and will be taken into operating income at the beginning of 2015 to offset funding from all entities in the region. The balance, plus any penalties billed and collected prior to June 30, 2015 will be held and accounted for in the 2015 budget submission.

The Company is the registered entity for the FRCC Region Reliability Coordinator functions and as a Planning Authority within the FRCC region. As a NERC registered entity, the Company must comply with applicable NERC reliability standards. Violations of these standards can result in financial penalties. The Company is involved in various enforcement actions for possible violations of electric reliability standards related to the NERC registered entity functions.

Several of the possible violations were self-reported by FRCC which may result in no penalty. At this time, the Company cannot fully determine the effect of the possible penalties that may arise. Based on the limited information available at this time the Company estimates that it is reasonably possible for a penalty to be assessed ranging from $75,000 to $200,000, however the Company cannot conclude that any amount within this range is a better estimate than any other. At December 31, 2014 the Company had $75,000 of accrued expenses recorded on the books for possible penalties.

NOTE 11: FUNCTIONAL EXPENSES

The detail of functional expenses for the year ended is as follows:

Statutory expenses:	
Reliability Standards Development	$ 256,204
Compliance & Enforcement	4,371,825
Reliability Assessment & Performance Analysis	1,114,642
Training & Education	258,835
Situational Awareness & Infrastructure	14,462
Total statutory expenses	$ 6,015,968
Member Services expenses:	
Planning Committee	$ 908,894
Operating Committee	7,008,204
General & Administrative	(1,090,170)
Total member services expenses	$ 6,826,928
Total Expenses	$ 12,842,896

NOTE 12: NET ASSETS

Unrestricted net assets that are designated are FERC-approved for statutory expense or board-approved for member services expense segregations of unrestricted net assets for specific projects. Since designations are voluntary and may be reversed or redirected by the governing board at any time, designated portions of net assets are not considered restricted.

The detail of unrestricted FERC or board-designated net assets is as follows at year end:

Statutory	$ 1,921,880
Member Services	898,503
Total unrestricted-board designated net assets	$ 2,820,383

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
TOTAL COMPANY
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 5,488,056	$ 5,488,057	$ (1)	
Penalty Sanctions	343,000	343,000	-	
Total ERO Funding	$ 5,831,056	$ 5,831,057	$ (1)	$ -
Membership Dues	$ 6,916,763	$ 6,916,762	1	
Testing Fees	-	-	-	
Services & Software	354,412	301,419	52,993	
Workshops	115,904	90,000	25,904	
Interest	-	-	-	
Special Assessment	-	-	-	
NonCash Post Ret Gain (Loss)	(108,814)	-	(108,814)	
Total Funding	**$ 13,109,321**	**$ 13,139,238**	**$ (29,917)**	-0.2%
Expenses				
Personnel Expenses				
Salaries	$ 5,600,880	$ 5,915,455	(314,575)	
Payroll Taxes	353,268	372,333	(19,065)	
Benefits	855,969	1,008,050	(152,081)	
Retirement Costs	735,317	931,148	(195,831)	
Total Personnel Expenses	**$ 7,545,434**	**$ 8,226,986**	**$ (681,552)**	-8.3%
Meeting Expenses				
Meetings	$ 96,181	$ 118,445	(22,264)	
Travel	163,244	230,925	(67,681)	
Conference Calls	43,969	45,879	(1,910)	
Total Meeting Expenses	**$ 303,394**	**$ 395,249**	**$ (91,855)**	-23.2%
Operating Expenses				
Consultants & Contracts	$ 4,247,959	$ 4,006,436	241,523	
Office Rent	812,686	779,924	32,762	
Office Costs	593,025	537,455	55,570	
Professional Services	53,105	196,552	(143,447)	
Miscellaneous	185,000	-	185,000	
Depreciation	192,463	134,388	58,075	
Total Operating Expenses	**$ 6,084,238**	**$ 5,654,755**	**$ 429,483**	7.6%
Total Indirect Expenses	**$ -**	**$ -**	**$ -**	
Other Non-Operating Expenses	**$ (1,090,170)**	**$ -**	**$ (1,090,170)**	
Total Expenses	**$ 12,842,896**	**$ 14,276,990**	**$ (1,434,094)**	-10.0%
Change in Assets	**$ 266,425**	**$ (1,137,752)**	**$ 1,404,177**	-100.0%
Non-Cash Expenses & Fixed Asset Expenditures				
Depreciation	$ (192,463)	$ (134,388)	$ (58,075)	
Net Non Pension Post Retir. Oblig	981,356	-	981,356	
Software CapEx	144,832	50,000	94,832	
Furniture & Fixtures CapEx	4,494	14,750	(10,256)	
Equipment & Computers CapEx	25,311	40,575	(15,264)	
Leasehold Improvements	-	3,000	(3,000)	
Increase/(Decrease) in Fixed Assets	**$ 963,530**	**$ (26,063)**	**$ 989,593**	100.0%
Total Budget	**$ 13,806,426**	**$ 14,250,927**	**$ (444,501)**	-3.1%
CHANGE IN WORKING CAPITAL	**$ (697,105)**	**$ (1,111,689)**	**$ 414,584**	100.0%
FTEs	41.96	47.24	(5.28)	
Beginning Working Capital 1/1/2014	3,542,040	2,299,266	1,242,774	
Change in Working Capital	(697,105)	(1,111,689)	414,584	
Working Capital at 12/31/2014	2,844,935	1,187,577	1,657,358	

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
TOTAL Statutory Only
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 5,488,056	$ 5,488,057	$ (1)	
Penalty Sanctions	343,000	343,000	-	
Total ERO Funding	$ 5,831,056	$ 5,831,057	$ (1)	
Membership Dues	-	-	-	
Testing Fees	-	-	-	
Services & Software	24,000	24,000	-	
Workshops	115,904	90,000	25,904	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ 5,970,960**	**$ 5,945,057**	**$ 25,903**	0.4%
Expenses				
Personnel Expenses				
Salaries	$ 3,414,283	$ 3,806,631	$ (392,348)	
Payroll Taxes	216,176	239,599	(23,423)	
Benefits	514,881	657,255	(142,374)	
Retirement Costs	451,593	602,881	(151,288)	
Total Personnel Expenses	**$ 4,596,933**	**$ 5,306,366**	**$ (709,433)**	-13.4%
Meeting Expenses				
Meetings	$ 63,639	$ 80,930	$ (17,291)	
Travel	121,969	167,209	(45,240)	
Conference Calls	16,803	18,771	(1,968)	
Total Meeting Expenses	**$ 202,411**	**$ 266,910**	**$ (64,499)**	-24.2%
Operating Expenses				
Consultants & Contracts	$ 357,495	$ 348,768	$ 8,727	
Office Rent	553,809	555,089	(1,280)	
Office Costs	124,505	118,343	6,162	
Professional Services	27,635	116,642	(89,007)	
Miscellaneous	-	-	-	
Depreciation	153,180	110,490	42,690	
Total Operating Expenses	**$ 1,216,624**	**$ 1,249,332**	**$ (32,708)**	-2.6%
Total Indirect Expenses	**$ -**	**$ -**	**$ -**	
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ 6,015,968**	**$ 6,822,608**	**$ (806,640)**	-11.8%
Change in Assets	**$ (45,008)**	**$ (877,551)**	**$ 832,543**	**-94.9%**
Fixed Asset Expenditures				
Depreciation	$ (153,180)	$ (110,490)	$ (42,690)	
Software CapEx	117,832	50,000	67,832	
Furniture & Fixtures CapEx	594	3,550	(2,956)	
Equipment & Computers CapEx	19,109	26,264	(7,155)	
Leasehold Improvements	-	3,000	(3,000)	
Increase/(Decrease) in Fixed Assets	**$ (15,645)**	**$ (27,676)**	**$ 12,031**	-43.5%
Total Budget	**$ 6,000,323**	**$ 6,794,932**	**$ (794,609)**	-11.7%
CHANGE IN WORKING CAPITAL	**$ (29,363)**	**$ (849,875)**	**$ 820,512**	**-96.5%**
FTEs	25.59	30.40	(4.81)	
Beginning Working Capital 1/1/2014	1,825,310	1,416,119	409,191	
Change in Working Capital	(29,363)	(849,875)	820,512	
Working Capital at 12/31/2014	1,795,947	566,244	1,229,703	

See Independent Auditors' Report

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
RELIABILITY STANDARDS
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 387,520	$ 387,519	$ 1	
Penalty Sanctions	22,072	22,072	-	
Total ERO Funding	$ 409,592	$ 409,591	$ 1	
Membership Dues		$ -	-	
Testing Fees		-	-	
Services & Software			-	
Workshops			-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ 409,592**	**$ 409,591**	**$ 1**	0.0%
Expenses				
Personnel Expenses				
Salaries	141,669	$ 217,880	(76,211)	
Payroll Taxes	8,427	13,714	(5,287)	
Benefits	19,964	33,809	(13,845)	
Retirement Costs	16,629	34,595	(17,966)	
Total Personnel Expenses	**$ 186,689**	**$ 299,998**	**$ (113,309)**	-37.8%
Meeting Expenses				
Meetings	$ 1,533	$ 2,080	(547)	
Travel	10,548	24,913	(14,365)	
Conference Calls	8	174	(166)	
Total Meeting Expenses	**$ 12,089**	**$ 27,167**	**$ (15,078)**	-55.5%
Operating Expenses				
Consultants & Contracts	$ 5,030	$ 4,529	501	
Office Rent	16,817	23,230	(6,413)	
Office Costs	4,769	6,324	(1,555)	
Professional Services	1,146	7,482	(6,336)	
Miscellaneous			-	
Depreciation	938	852	86	
Total Operating Expenses	**$ 28,700**	**$ 42,417**	**$ (13,717)**	-32.3%
Total Indirect Expenses	**$ 28,726**	**$ 40,017**	**$ (11,291)**	-28.2%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ 256,204**	**$ 409,599**	**$ (153,395)**	-37.5%
Change in Assets	**$ 153,388**	**$ (8)**	**$ 153,396**	100.0%
Fixed Asset Expenditures				
Depreciation	$ (938)	$ (852)	$ (86)	
Software CapEx			-	
Furniture & Fixtures CapEx			-	
Equipment & Computers CapEx	2,383	840	1,543	
Leasehold Improvements			-	
Increase/(Decrease) in Fixed Assets	**$ 1,445**	**$ (12)**	**$ 1,457**	-12141.7%
Total Budget	**$ 257,649**	**$ 409,587**	**$ (151,938)**	-37.1%
CHANGE IN WORKING CAPITAL	**$ 151,943**	**$ 4**	**$ 151,939**	
Direct FTEs	1.09	1.73	(0.64)	-37.0%
Indirect FTE's	0.15	0.22	(0.07)	-31.8%
Total FTE's	1.24	1.95	(0.71)	-36.4%

See Independent Auditors' Report

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
COMPLIANCE
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 4,458,038	$ 4,458,040	$ (2)	
Penalty Sanctions	244,311	244,311	-	
Total ERO Funding	$ 4,702,349	$ 4,702,351	$ (2)	
Membership Dues	-	$ -	-	
Testing Fees		-	-	
Services & Software			-	
Workshops			-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ 4,702,349**	**$ 4,702,351**	**$ (2)**	0.0%
Expenses				
Personnel Expenses				
Salaries	$ 2,222,713	$ 2,411,701	(188,988)	
Payroll Taxes	141,615	151,798	(10,183)	
Benefits	344,837	452,812	(107,975)	
Retirement Costs	296,800	382,958	(86,158)	
Total Personnel Expenses	**$ 3,005,965**	**$ 3,399,269**	**$ (393,304)**	-11.6%
Meeting Expenses				
Meetings	$ 14,402	$ 4,915	9,487	
Travel	67,379	92,966	(25,587)	
Conference Calls	2,444	4,565	(2,121)	
Total Meeting Expenses	**$ 84,225**	**$ 102,446**	**$ (18,221)**	-17.8%
Operating Expenses				
Consultants & Contracts	$ 178,717	$ 119,235	59,482	
Office Rent	412,115	406,366	5,749	
Office Costs	73,149	69,926	3,223	
Professional Services	20,919	83,069	(62,150)	
Miscellaneous			-	
Depreciation	146,391	101,598	44,793	
Total Operating Expenses	**$ 831,291**	**$ 780,194**	**$ 51,097**	6.5%
Total Indirect Expenses	**$ 450,344**	**$ 442,995**	**$ 7,349**	1.7%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ 4,371,825**	**$ 4,724,904**	**$ (353,079)**	-7.5%
Change in Assets	**$ 330,524**	**$ (22,553)**	**$ 353,077**	
Fixed Asset Expenditures				
Depreciation	$ (146,391)	$ (101,598)	$ (44,793)	
Software CapEx	117,832	50,000	67,832	
Furniture & Fixtures CapEx	594	3,550	(2,956)	
Equipment & Computers CapEx	15,843	22,496	(6,653)	
Leasehold Improvements		3,000	(3,000)	
Increase/(Decrease) in Fixed Assets	**$ (12,122)**	**$ (22,552)**	**$ 10,430**	
Total Budget	**$ 4,359,703**	**$ 4,702,352**	**$ (342,649)**	-7.3%
CHANGE IN WORKING CAPITAL	**$ 342,646**	**$ (1)**	**$ 342,647**	
Direct FTEs	16.64	19.26	(2.62)	-13.6%
Indirect FTE's	2.33	2.39	(0.06)	-2.5%
Total FTE's	18.97	21.65	(2.68)	-12.4%

See Independent Auditors' Report

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
RELIABILITY ASSESSMENT
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 1,300,196	$ 1,300,196	$ -	
Penalty Sanctions	67,103	67,103	-	
Total ERO Funding	$ 1,367,299	$ 1,367,299	$ -	
Membership Dues	-	$ -	-	
Testing Fees		-	-	
Services & Software	24,000	24,000	-	
Workshops			-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ 1,391,299**	**$ 1,391,299**	**$ -**	0.0%
Expenses				
Personnel Expenses				
Salaries	$ 551,170	$ 662,404	(111,234)	
Payroll Taxes	34,626	41,693	(7,067)	
Benefits	80,475	99,378	(18,903)	
Retirement Costs	70,926	105,185	(34,259)	
Total Personnel Expenses	**$ 737,197**	**$ 908,660**	**$ (171,463)**	-18.9%
Meeting Expenses				
Meetings	$ 6,372	$ 6,674	(302)	
Travel	41,348	43,265	(1,917)	
Conference Calls	8,558	8,543	15	
Total Meeting Expenses	**$ 56,278**	**$ 58,482**	**$ (2,204)**	-3.8%
Operating Expenses				
Consultants & Contracts	$ 118,883	$ 192,989	$ (74,106)	
Office Rent	65,377	70,623	(5,246)	
Office Costs	16,535	13,480	3,055	
Professional Services	5,051	22,829	(17,778)	
Miscellaneous			-	
Depreciation	3,498	3,376	122	
Total Operating Expenses	**$ 209,344**	**$ 303,297**	**$ (93,953)**	-31.0%
Total Indirect Expenses	**$ 111,823**	**$ 121,676**	**$ (9,853)**	-8.1%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ 1,114,642**	**$ 1,392,115**	**$ (277,473)**	-19.9%
Change in Assets	**$ 276,657**	**$ (816)**	**$ 277,473**	
Fixed Asset Expenditures				
Depreciation	$ (3,498)	$ (3,376)	$ (122)	
Software CapEx			-	
Furniture & Fixtures CapEx			-	
Equipment & Computers CapEx	731	2,562	(1,831)	
Leasehold Improvements			-	
Increase/(Decrease) in Fixed Assets	**$ (2,767)**	**$ (814)**	**$ (1,953)**	239.9%
Total Budget	**$ 1,111,875**	**$ 1,391,301**	**$ (279,426)**	-20.1%
CHANGE IN WORKING CAPITAL	**$ 279,424**	**$ (2)**	**$ 279,426**	
Direct FTEs	4.13	5.29	(1.16)	-21.9%
Indirect FTE's	0.58	0.66	(0.08)	-12.1%
Total FTE's	4.71	5.95	(1.24)	-20.8%

See Independent Auditors' Report

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
TRAINING AND EDUCATION
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 173,812	$ 173,812	$ -	
Penalty Sanctions	8,499	8,499	-	
Total ERO Funding	$ 182,311	$ 182,311	$ -	
Membership Dues	-	$ -	-	
Testing Fees		-	-	
Services & Software			-	
Workshops	115,904	90,000	25,904	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ 298,215**	**$ 272,311**	**$ 25,904**	9.5%
Expenses				
Personnel Expenses				
Salaries	$ 72,421	$ 83,896	(11,475)	
Payroll Taxes	4,621	5,281	(660)	
Benefits	20,781	11,616	9,165	
Retirement Costs	10,458	13,325	(2,867)	
Total Personnel Expenses	**$ 108,281**	**$ 114,118**	**$ (5,837)**	-5.1%
Meeting Expenses				
Meetings	$ 41,298	$ 67,248	(25,950)	
Travel	2,634	5,996	(3,362)	
Conference Calls	5,793	5,481	312	
Total Meeting Expenses	**$ 49,725**	**$ 78,725**	**$ (29,000)**	-36.8%
Operating Expenses				
Consultants & Contracts	$ 51,695	$ 29,259	22,436	
Office Rent	8,732	8,945	(213)	
Office Costs	23,779	22,610	1,169	
Professional Services	449	2,916	(2,467)	
Miscellaneous			-	
Depreciation	725	590	135	
Total Operating Expenses	**$ 85,380**	**$ 64,320**	**$ 21,060**	32.7%
Total Indirect Expenses	**$ 15,449**	**$ 15,412**	**$ 37**	0.2%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ 258,835**	**$ 272,575**	**$ (13,740)**	-5.0%
Change in Assets	**$ 39,380**	**$ (264)**	**$ 39,644**	
Fixed Asset Expenditures				
Depreciation	$ (725)	$ (590)	$ (135)	
Software CapEx			-	
Furniture & Fixtures CapEx			-	
Equipment & Computers CapEx	142	327	(185)	
Leasehold Improvements			-	
Increase/(Decrease) in Fixed Assets	**$ (583)**	**$ (263)**	**$ (320)**	121.7%
Total Budget	**$ 258,252**	**$ 272,312**	**$ (14,060)**	-5.2%
CHANGE IN WORKING CAPITAL	**$ 39,963**	**$ (1)**	**$ 39,964**	
Direct FTEs	0.54	0.68	(0.14)	-20.6%
Indirect FTE's	0.08	0.08	-	0.0%
Total FTE's	0.62	0.76	(0.14)	-18.4%

See Independent Auditors' Report

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
SITUATIONAL AWARENESS
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ 18,365	$ 18,365	$ -	
Penalty Sanctions	1,015	1,015	-	
Total ERO Funding	$ 19,380	$ 19,380	$ -	
Membership Dues	-	$ -	-	
Testing Fees		-	-	
Services & Software			-	
Workshops			-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ 19,380**	**$ 19,380**	**$ -**	0.0%
Expenses				
Personnel Expenses				
Salaries	$ 6,362	$ 10,017	(3,655)	
Payroll Taxes	446	631	(185)	
Benefits	789	1,387	(598)	
Retirement Costs	879	1,591	(712)	
Total Personnel Expenses	**$ 8,476**	**$ 13,626**	**$ (5,150)**	-37.8%
Meeting Expenses				
Meetings	$ 34	$ 13	21	
Travel	60	69	(9)	
Conference Calls	-	8	(8)	
Total Meeting Expenses	**$ 94**	**$ 90**	**$ 4**	4.4%
Operating Expenses				
Consultants & Contracts	$ 217	$ 209	8	
Office Rent	738	1,068	(330)	
Office Costs	1,996	2,162	(166)	
Professional Services	70	346	(276)	
Miscellaneous			-	
Depreciation	1,628	2,431	(803)	
Total Operating Expenses	**$ 4,649**	**$ 6,216**	**$ (1,567)**	-25.2%
Total Indirect Expenses	**$ 1,243**	**$ 1,840**	**$ (597)**	-32.4%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ 14,462**	**$ 21,772**	**$ (7,310)**	-33.6%
Change in Assets	**$ 4,918**	**$ (2,392)**	**$ 7,310**	
Fixed Asset Expenditures				
Depreciation	$ (1,628)	$ (2,431)	$ 803	
Software CapEx			-	
Furniture & Fixtures CapEx			-	
Equipment & Computers CapEx	10	39	(29)	
Leasehold Improvements			-	
Increase/(Decrease) in Fixed Assets	**$ (1,618)**	**$ (2,392)**	**$ 774**	-32.4%
Total Budget	**$ 12,844**	**$ 19,380**	**$ (6,536)**	-33.7%
CHANGE IN WORKING CAPITAL	**$ 6,536**	**$ -**	**$ 6,536**	
Direct FTEs	0.04	0.08	(0.04)	-50.0%
Indirect FTE's	0.01	0.01	-	0.0%
Total FTE's	0.05	0.09	(0.04)	-44.4%

See Independent Auditors' Report

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
GENERAL ADMINISTRATIVE
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ (849,875)	$ (849,875)	$ -	
Penalty Sanctions		-	-	
Total ERO Funding	$ (849,875)	$ (849,875)	$ -	
Membership Dues	-	$ -	-	
Testing Fees		-	-	
Services & Software			-	
Workshops			-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ (849,875)**	**$ (849,875)**	**$ -**	0.0%
Expenses				
Personnel Expenses				
Salaries	$ 419,948	$ 420,733	$ (785)	
Payroll Taxes	26,441	26,482	(41)	
Benefits	48,035	58,253	(10,218)	
Retirement Costs	55,901	65,227	(9,326)	
Total Personnel Expenses	**$ 550,325**	**$ 570,695**	**$ (20,370)**	-3.6%
Meeting Expenses				
Meetings			$ -	
Travel			-	
Conference Calls		-	-	
Total Meeting Expenses	**$ -**	**$ -**	**$ -**	
Operating Expenses				
Consultants & Contracts	$ 2,953	$ 2,547	$ 406	
Office Rent	50,030	44,857	5,173	
Office Costs	4,277	3,841	436	
Professional Services		-	-	
Miscellaneous			-	
Depreciation		1,643	(1,643)	
Total Operating Expenses	**$ 57,260**	**$ 52,888**	**$ 4,372**	8.3%
Total Indirect Expenses	**$ (607,585)**	**$ (621,940)**	**$ 14,355**	
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**$ -**	**$ 1,643**	**$ (1,643)**	**-100.0%**
Change in Assets	**$ (849,875)**	**$ (851,518)**	**$ 1,643**	-0.2%
Fixed Asset Expenditures				
Depreciation	$ -	$ (1,643)	$ 1,643	
Software CapEx			-	
Furniture & Fixtures CapEx			-	
Equipment & Computers CapEx			-	
Leasehold Improvements			-	
Increase/(Decrease) in Fixed Assets	**$ -**	**$ (1,643)**	**$ 1,643**	
Total Budget	**$ -**	**$ -**	**$ -**	
CHANGE IN WORKING CAPITAL	**$ (849,875)**	**$ (849,875)**	**$ -**	0.0%
FTEs	3.15	3.36	(0.21)	-6.3%

Florida Reliability Coordinating Council, Inc.
Statement of Activities - Total Actual To Total Budget
TOTAL MEMBER SERVICES - NON STATUTORY
December 31, 2014

(In Whole Dollars)

	2014 Actual	2014 Budget	2014 Variance	%
Funding				
ERO Funding				
ERO Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	$ -	$ -	$ -	
Membership Dues	6,916,763	6,916,762	1	
Testing Fees	-	-	-	
Services & Software	330,412	277,419	52,993	
Workshops	-	-	-	
Special Assessment	-	-	-	
Non Cash Postretirement	(108,814)	-	(108,814)	
Total Funding	**$ 7,138,361**	**$ 7,194,181**	**$ (55,820)**	-0.8%
Expenses				
Personnel Expenses				
Salaries	$ 2,186,597	$ 2,108,824	77,773	
Payroll Taxes	137,092	132,734	4,358	
Benefits	341,088	350,795	(9,707)	
Retirement Costs	283,724	328,267	(44,543)	
Total Personnel Expenses	**$ 2,948,501**	**$ 2,920,620**	**$ 27,881**	1.0%
Meeting Expenses				
Meetings	$ 32,542	$ 37,515	(4,973)	
Travel	41,275	63,716	(22,441)	
Conference Calls	27,166	27,108	58	
Total Meeting Expenses	**$ 100,983**	**$ 128,339**	**$ (27,356)**	-21.3%
Operating Expenses				
Consultants & Contracts	$ 3,890,464	$ 3,657,668	232,796	
Office Rent	258,877	224,835	34,042	
Office Costs	468,520	419,112	49,408	
Professional Services	25,470	79,910	(54,440)	
Miscellaneous	185,000	-	185,000	
Depreciation	39,283	23,898	15,385	
Total Operating Expenses	**$ 4,867,614**	**$ 4,405,423**	**$ 462,191**	10.5%
Total Indirect Expenses				
Other Non-Operating Expenses	**$ (1,090,170)**	**$ -**	**$ (1,090,170)**	
Total Expenses	**$ 6,826,928**	**$ 7,454,382**	**$ (627,454)**	-8.4%
Change in Assets	**$ 311,433**	**$ (260,201)**	**$ 571,634**	
Non-Cash Expenses & Fixed Asset Expenditures				
Depreciation	$ (39,283)	$ (23,898)	$ (15,385)	
Net Non Pension Post Retir. Oblig	981,356	-	981,356	
Software CapEx	27,000	-	27,000	
Furniture & Fixtures CapEx	3,900	11,200	(7,300)	
Equipment & Computers CapEx	6,202	14,311	(8,109)	
Leasehold Improvements	-	-	-	
Increase/(Decrease) in Fixed Assets	**$ 979,175**	**$ 1,613**	**$ 977,562**	60605.2%
Total Budget	**$ 7,806,103**	**$ 7,455,995**	**$ 350,108**	4.7%
CHANGE IN WORKING CAPITAL	**$ (667,742)**	**$ (261,814)**	**$ (405,928)**	
FTEs	16.37	16.84	(0.47)	
Beginning Working Capital 1/1/2014	1,716,730	883,147	833,583	
Change in Working Capital	(667,742)	(261,814)	(405,928)	
Working Capital at 12/31/2014	1,048,988	621,333	427,655	

See Independent Auditors' Report

FINANCIAL STATEMENTS

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January 29, 2015

The Corporate Compliance, Finance & Audit Committee
Florida Reliability Coordinating Council, Inc.

We are pleased to present the results of our audit of the 2014 financial statements of Florida Reliability Coordinating Council, Inc. (the "Organization").

This report to the Corporate Compliance, Finance & Audit Committee (the "Committee") summarizes our audit, the report issued and various analyses and observations related to the Organization's accounting and reporting. The document also contains the communications required by our professional standards.

Our audit was designed, primarily to express an opinion on the Organization's 2014 financial statements. We considered the Organization's current and emerging business needs, along with an assessment of risks that could materially affect the financial statements, and aligned our audit procedures accordingly. We conducted the audit with the objectivity and independence that you expect. We received the full support and assistance of Florida Reliability Coordinating Council, Inc. (the "Organization") personnel.

At Carr, Riggs & Ingram, LLC (CRI), we are continually evaluating the quality of our professionals' work in order to deliver audit services of the highest quality that will meet or exceed your expectations. We encourage you to provide any feedback you believe is appropriate to ensure that we do not overlook a single detail as it relates to the quality of our services.

This report is intended solely for the information and use of the Committee and others within the Organization and should not be used by anyone other than these specified parties.

We appreciate this opportunity to work with you. If you have any questions or comments, please contact me at 727-324-1241 or lkidder@cricpa.com.

Very truly yours,

Lorri J. Kidder

Lorri J. Kidder, CPA, CFE, CGMA
Partner

As discussed with the Corporate Compliance, Finance & Audit Committee (the "Committee") during our planning process, our audit plan represented an approach responsive to the assessment of risk for the Organization. Specifically, we planned and performed our audit to:

- Perform audit services, as requested by the Committee, in accordance with auditing standards generally accepted in the United States of America, in order to express an opinion on the Organization's financial statements for the year ended December 31, 2014;
- Communicate directly with the Committee regarding the results of our procedures;
- Address with the Committee any accounting and financial reporting issues;
- Anticipate and respond to concerns of the Committee; and
- Other audit-related projects as they arise and upon request.

We have audited the financial statements of Florida Reliability Coordinating Council, Inc. for the year ended December 31, 2014, and have issued our report thereon dated January 29, 2015. Professional standards require that we provide you with the following information related to our audit:

MATTER TO BE COMMUNICATED	AUDITOR'S RESPONSE
Auditor's responsibility under Generally Accepted Auditing Standards	As stated in our engagement letter dated August 29, 2014, our responsibility, as described by professional standards, is to express an opinion about whether the financial statements prepared by management with your oversight are fairly presented, in all material respects, in conformity with accounting principles generally accepted in the United States of America (GAAP). Our audit of the financial statements does not relieve you or management of your responsibilities. As part of our audit, we considered the internal control of the Organization. Such considerations were solely for the purpose of determining our audit procedures and not to provide any assurance concerning such internal control.
Client's responsibility	Management, with oversight from those charged with governance, is responsible for establishing and maintaining internal controls, including monitoring ongoing activities; for the selection and application of accounting principles; and for the fair presentation in the statements of revenue and expenses, and the statements of assets, liabilities, and net assets in conformity with the applicable framework. Management is responsible for the design and implementation of programs and controls to prevent and detect fraud.
Planned scope and timing of the audit	Our initial audit plan was not significantly altered during our fieldwork.
Management judgments and accounting estimates *The process used by management in forming particularly sensitive accounting estimates and the basis for the auditor's conclusion regarding the reasonableness of those estimates.*	Please see the following section titled "Accounting Policies, Judgments and Sensitive Estimates and CRI Comments on Quality."
Potential effect on the financial statements of any significant risks and exposures *Major risks and exposures facing the Fund and how they are disclosed.*	No such risks or exposures were noted.

MATTER TO BE COMMUNICATED	AUDITOR'S RESPONSE
Significant accounting policies, including critical accounting policies and alternative treatments within generally accepted accounting principles and the auditor's judgment about the quality of accounting principles • *The initial selection of and changes in significant accounting policies or their application; methods used to account for significant unusual transactions; and effect of significant policies in controversial or emerging areas for which there is a lack of authoritative guidance or consensus.* • *The auditor should also discuss the auditor's judgment about the quality, not just the acceptability, of the Organization's accounting policies as applied in its financial reporting. The discussion should include such matters as consistency of accounting policies and their application, and clarity and completeness of the financial statements, including disclosures. Critical accounting policies and practices applied by the Organization in its financial statements and our assessment of management's disclosures regarding such policies and practices (including any significant modifications to such disclosures proposed by us but rejected by management), the reasons why certain policies and practices are or are not considered critical, and how current and anticipated future events impact those determinations.*	None.
Significant difficulties encountered in the audit *Any significant difficulties, for example, unreasonable logistical constraints or lack of cooperation by management.*	None.
Disagreements with management *Disagreements, whether or not subsequently resolved, about matters significant to the financial statements or auditor's report. This does not include those that came about based on incomplete facts or preliminary information.*	None.

MATTER TO BE COMMUNICATED	AUDITOR'S RESPONSE
Other findings or issues *Matters significant to oversight of the financial reporting practices by those charged with governance. For example, an entity's failure to obtain the necessary type of audit, such as one under Government Auditing Standards, in addition to GAAS.*	None.
Matters arising from the audit that were discussed with, or the subject of correspondence with, management *Business conditions that might affect risk or discussions regarding accounting practices or application of auditing standards.*	None.
Corrected and uncorrected misstatements *All significant audit adjustments arising from the audit, whether or not recorded by the Organization, that could individually or in the aggregate have a significant effect on the financial statements. We should also inform the Committee about uncorrected misstatements aggregated by us during the current engagement and pertaining to the latest period presented, that were determined by management to be immaterial, both individually and in the aggregate, to the financial statements taken as a whole. Any internal control deficiencies that could have prevented the misstatements.*	None.
Major issues discussed with management prior to retention *Any major accounting, auditing or reporting issues discussed with management in connection with our initial or recurring retention.*	None.
Consultations with other accountants *When management has consulted with other accountants about significant accounting or auditing matters.*	None of which we are aware.
Written representations *A description of the written representations the auditor requested (or a copy of the representation letter).*	See "Management Representation Letter" section.

MATTER TO BE COMMUNICATED	AUDITOR'S RESPONSE
Internal control deficiencies *Any significant deficiencies or material weaknesses in the design or operation of internal control that came to the auditor's attention during the audit.*	None.
Fraud and illegal acts *Fraud involving the Organization Corporate Compliance, Finance & Audit Committee or those responsible for internal controls, or causing a material misstatement of the financial statements, where the auditor determines there is evidence that such fraud may exist. Any illegal acts coming to the auditor's attention involving senior management and any other illegal acts, unless clearly inconsequential.*	We are unaware of any fraud or illegal acts involving management or causing material misstatement of the financial statements.
Other information in documents containing audited financial statements *The external auditor's responsibility for information in a document containing audited financial statements, as well as any procedures performed and the results.*	Our responsibility related to documents (including annual reports, websites, etc.) containing the financial statements is to read the other information to consider whether: • Such information is materially inconsistent with the financial statements; and • We believe such information represents a material misstatement of fact. We have not been provided any such items to date and are unaware of any other documents that contain the audited financial statements.

Accounting Policies, Judgments, & Sensitive Estimates & CRI Comments on Quality

We are required to communicate our judgments about the quality, not just the acceptability, of the Organization's accounting principles as applied in its financial reporting. We are also required to communicate critical accounting policies and sensitive accounting estimates. The Committee may wish to monitor throughout the year the process used to compute and record these accounting estimates. The table below summarizes our communications regarding these matters.

AREA	ACCOUNTING POLICY	CRITICAL POLICY?	JUDGMENTS & SENSITIVE ESTIMATE	COMMENTS ON QUALITY OF ACCOUNTING POLICY & APPLICATION
Fixed Assets	Useful lives of depreciable assets range from 3-7 years and depreciated on a straight-line basis. Leasehold improvements are amortized over the lives of the respective leases or the service lives of the improvements, whichever is shorter.	X	A sensitive estimate for the Organization is the useful lives of fixed assets.	The Organization's policies are in accordance with accounting principles generally accepted in the United States of America (GAAP).
Postretirement Benefits Other Than Pensions	Employees hired before 10/1/2003, also meeting additional conditions, are eligible for postretirement health care. The health coverage includes full coverage from age 60 to 65, if retired, and an annual amount of $4,200 per year funded to an HRA after age 65 in lieu of health coverage.	X	A sensitive estimate for the Organization due to the use of Actuarial calculations.	The Organization's policies are in accordance with accounting principles generally accepted in the United States of America (GAAP).

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
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TAMPA, FLORIDA 33607-8410
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WWW.FRCC.COM

January 29, 2015

Carr, Riggs & Ingram, LLC
2111 Drew Street
Clearwater, FL 33765

This representation letter is provided in connection with your audit of the financial statements of Florida Reliability Coordinating Council, Inc., which comprise the statements of financial position as of December 31, 2014, and the related statements of activities and cash flows for the year then ended, and the related notes to the financial statements, for the purpose of expressing an opinion as to whether the financial statements are presented fairly, in all material respects, in accordance with accounting principles generally accepted in the United States (U.S. GAAP).

Certain representations in this letter are described as being limited to matters that are material. Items are considered material, regardless of size, if they involve an omission or misstatement of accounting information that, in light of surrounding circumstances, makes it probable that the judgment of a reasonable person relying on the information would be changed or influenced by the omission or misstatement. An omission or misstatement that is monetarily small in amount could be considered material as a result of qualitative factors.

We confirm, to the best of our knowledge and belief, as of January 29, 2015, the following representations made to you during your audit.

Financial Statements

1) We have fulfilled our responsibilities, as set out in the terms of the audit engagement letter dated August 29, 2014, including our responsibility for the preparation and fair presentation of the financial statements in accordance with U.S. GAAP.

2) The financial statements referred to above are fairly presented in conformity with U.S. GAAP.

3) We acknowledge our responsibility for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

4) We acknowledge our responsibility for the design, implementation, and maintenance of internal control to prevent and detect fraud.

5) Significant assumptions we used in making accounting estimates, including those measured at fair value, are reasonable.

6) Related party relationships and transactions have been appropriately accounted for and disclosed in accordance with U.S. GAAP.

7) All events subsequent to the date of the financial statements and for which U.S. GAAP requires adjustment or disclosure have been adjusted or disclosed.

8) The effects of all known actual or possible litigation, claims, and assessments have been accounted for and disclosed in accordance with U.S. GAAP.

9) Material concentrations have been appropriately disclosed in accordance with U.S. GAAP.

10) Guarantees, whether written or oral, under which the organization is contingently liable, have been properly recorded or disclosed in accordance with U.S. GAAP.

Information Provided

11) We have provided you with:

a) Access to all information, of which we are aware, that is relevant to the preparation and fair presentation of the financial statements, such as records, documentation, and other matters.

b) Additional information that you have requested from us for the purpose of the audit.

c) Unrestricted access to persons within the Organization from whom you determined it necessary to obtain audit evidence.

d) Minutes of the meetings of the governing board or summaries of actions of recent meetings for which minutes have not yet been prepared.

12) All material transactions have been recorded in the accounting records and are reflected in the financial statements.

13) We have disclosed to you the results of our assessment of the risk that the financial statements may be materially misstated as a result of fraud.

14) We have no knowledge of any fraud or suspected fraud that affects the organization and involves:

a) Management,

b) Employees who have significant roles in internal control, or

c) Others where the fraud could have a material effect on the financial statements.

15) We have no knowledge of any allegations of fraud or suspected fraud affecting the organization's financial statements communicated by employees, former employees, grantors, regulators, or others.

16) We have no knowledge of any instances of noncompliance or suspected noncompliance with laws and regulations whose effects should be considered when preparing financial statements.

17) We have disclosed to you all known actual or possible litigation, claims, and assessment whose effects should be considered when preparing the financial statements.

18) We have disclosed to you the identity of the organization's related parties and all the related party relationships and transactions of which we are aware.

19) The organization has satisfactory title to all owned assets, and there are no liens or encumbrances on such assets nor has any asset been pledged as collateral.

20) We are responsible for compliance with the laws, regulations, and provisions of contracts and grant agreements applicable to us.

21) Florida Reliability Coordinating Council, Inc. is an exempt organization under Section 501(c)6 of the Internal Revenue Code. Any activities of which we are aware that would jeopardize the Organization's tax-exempt status, and all activities subject to tax on unrelated business income or excise or other tax, have been disclosed to you. All required filings with tax authorities are up-to-date.

22) We acknowledge our responsibility for presenting the Statutory and Non-statutory schedules ('supplementary information") in accordance with U.S. GAAP, and we believe the supplementary information, including its form and content, is fairly presented in accordance with U.S. GAAP. The methods of measurement and presentation of the Statutory and Non-statutory schedules have not changed from those used in the prior period, and we have disclosed to you any significant assumptions or interpretations underlying the measurement and presentation of the supplementary information.

Reva Maskewitz

Reva Maskewitz, Controller

Stacy Dochoda

Stacy Dochoda, President & CEO

Communication of Internal Control Related Matters

The Corporate Compliance, Finance & Audit Committee
Florida Reliability Coordinating Council, Inc.

In planning and performing our audit of the financial statements of Florida Reliability Coordinating Council, Inc. as of and for the year ended December 31, 2014, in accordance with auditing standards generally accepted in the United States of America, we considered the Organization's internal control over financial reporting (internal control) as a basis for designing audit procedures that are appropriate in the circumstances for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Organization's internal control. Accordingly, we do not express an opinion on the effectiveness of the Organization's internal control.

A deficiency in internal control exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct, misstatements on a timely basis. A material weakness is a deficiency, or a combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of the organization's financial statements will not be prevented, or detected and corrected, on a timely basis.

Our consideration of internal control was for the limited purpose described in the first paragraph and was not designed to identify all deficiencies in internal control that might be material weaknesses. Given these limitations, during our audit we did not identify any deficiencies in internal control that we consider to be material weaknesses. However, material weaknesses may exist that have not been identified.

This communication is intended solely for the information and use of the Committee and management of the Organization and is not intended to be, and should not be, used by anyone other than these specified parties.

Carr, Riggs & Ingram, L.L.C.

CARR, RIGGS & INGRAM, LLC

Clearwater, Florida
January 29, 2015

ATTACHMENT 3

2014 ACTUAL COST-TO-BUDGET COMPARISON

AND

2014 AUDITED FINANCIAL REPORT

FOR

MIDWEST RELIABILITY ORGANIZATION

Midwest Reliability Organization

2014 MRO Budget True-Up

Date: April 28, 2015

380 St. Peter Street, Suite 800 • Saint Paul, MN 55102 •Phone (651) 855-1760 • Fax (651) 855-1712
www.midwestreliability.org

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Section B — Supplemental Financial Information ***27***

2014 Statutory Summary Budget Variance

Consolidated	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	8,741,442	8,741,442	-	
Penalty Sanctions	136,501	136,501	-	
Total ERO Funding	**$ 8,877,943**	**$ 8,877,943**	**$ -**	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ 8,877,943**	**$ 8,877,943**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	5,188,857	5,178,538	10,319	0.20%
Payroll Taxes	325,022	339,154	(14,132)	-4.17%
Employee Benefits	381,964	412,222	(30,258)	-7.34%
Savings & Retirement	836,802	968,920	(132,118)	-13.64%
Total Personnel Expenses	**6,732,645**	**6,898,833**	**(166,189)**	-2.41%
Meeting Expenses				
Meetings	79,231	100,514	(21,283)	-21.17%
Travel	492,858	598,900	(106,042)	-17.71%
Conference Calls	251	-	251	
Total Meeting Expenses	**572,340**	**699,414**	**(127,074)**	-18.17%
Operating Expenses				
Consultants & Contracts	929,195	543,100	386,095	71.09%
Rent & Improvements	492,489	524,827	(32,338)	-6.16%
Office Costs	450,368	503,124	(52,756)	-10.49%
Professional Services	113,970	205,000	(91,030)	-44.40%
Miscellaneous	-	-	-	
Depreciation	477,930	471,000	6,930	1.47%
Total Operating Expenses	**2,463,952**	**2,247,051**	**216,901**	9.65%
Indirect Expenses	**-**	**-**	**-**	
Other Non-Operating Expenses	**241,454**	**-**	**241,454**	
Total Expenses (B)	**10,010,391**	**9,845,298**	**165,092**	
Change in Assets (A - B)	**(1,132,448)**	**(967,355)**	**(165,092)**	
Fixed Assets				
Depreciation	(477,930)	(471,000)	(6,930)	1.47%
Computer & Software CapEx	67,864	320,500	(252,636)	-78.83%
Furniture & Fixtures CapEx	6,844	-	6,844	
Equipment CapEx	-	-	-	
Leasehold Improvements	6,930	50,000	(43,070)	-86.14%
(Inc)Dec in Fixed Assets	$ (396,292)	$ (100,500)	$ (295,792)	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	**(396,292)**	**(100,502)**	**(295,792)**	
TOTAL BUDGET (B + C)	**9,614,099**	**9,744,796**	**(130,700)**	-1.34%
Change in Working Capital (A-B-C)	**(736,156)**	**(866,853)**	**130,700**	
FTEs	**39.6**	**40.8**	**(1.2)**	

Summary of Financials and Resources

MRO staff reports the audited final numbers for 2014 to be 1.34% under budget. Prior to the annual actuarial calculation of post-retirement medical benefit obligation (discount rate, expected rate of return on plan assets and health care cost trend rate), MRO staff reported 2014 expenses to be 2.55% under budget.

While MRO was under budget, MRO staff believes the principal responsibilities under the delegation agreement were met in 2014. Some highlights:

- Conducted twelve audits, including six combined CIP/operations and planning audits and one joint audit lead by another Regional Entity
- Closed 184 instances of noncompliance (violations, remediated issues, or compliance exceptions) in 2014, reducing the numbers of days in CMEP processing from 533 in 2013 to 165 days by the end of 2014, an improvement of 368 days (over 300%)
- Processed 15 revisions to registration
- Completed the seasonal and long-term reliability assessments for the year
- Provided oversight on the analysis of 14 events in the region. Data was collected for the metrics developed on the events and causes, as well as for the performance of protection systems, and assessed situation awareness information provided by Registered Entities.
- Organized and completed several workshops in support of regional reliability, in addition to other outreach activities
- Contributed to numerous NERC working groups, including 3,389 staff hours to the Reliability Assurance Initiative

As requested, the year-to-date variances greater than $10,000 and 10 percent are explained below, as well as expenses not budgeted.

Personnel Expenses (Actual - $166,189 (-2.41%) under budget)
Although total Personnel Expenses were only 2.41% under budget, Savings & Retirement expense was $132,118 (13.63%) under budget because the annual post-retirement adjustment reduced the net periodic cost for 2014 provided by third party advisors.

Meeting and Travel Expenses (Actual - $127,074 (-18.17%) under budget)
Meeting expenses were under budget by $21,283. Staff is able to host more meetings in the new MRO facility. Eliminating the rental costs of meeting rooms and audio visual equipment, as well as lowering catering costs, reduced costs more than anticipated.

Travel expenses were under budget by $106,042. Greater than budgeted internally-hosted meetings reduced travel. Other contributing factors included: shorter duration of on-site audits and participation by fewer auditors; in-person participation in fewer working group meetings; and attendance at fewer NERC Board of Trustee meetings.

Conference call expenses were over budget by $251. Back-up service for conferencing was not budgeted for in 2014.

Consultants & Contracts (Actual – $386,095 (71.09%) over budget)
MRO had an increase in consultant use due to the upgrade of MRO's website, the implementation of SharePoint, and the use of a recruiter for certain positions. The costs incurred for these unbudgeted items were offset by reductions in other areas, most notably a decrease in the need for capital expenditures. By accelerating capital expenditures in late 2013, MRO was able to partially offset the 2014 overage in consulting and contracts.

Office Costs (Actual - $52,756 (-10.49%) under budget)
Training costs were lower than budget partially due to dollars being budgeted in the discretionary tuition reimbursement program that were not pursued by staff in 2014. Additionally, staff is encouraged if possible to take training locally. Finally, when staff has more than one certification or required CEUs in more than one area, they are strongly encouraged to seek training opportunities that can be applied to more than one area.

Professional Services (Actual - $91,030 (-44.40%) under budget)
External professional services are difficult to project because of the nature of these costs. Normally, costs are incurred in response to specific situations that develop. For 2014, the need for external professional services, including legal services and the time of independent MRO board members, was less than anticipated.

Other Non-Operating Expenses (Actual - $241,454 over budget)
The actuarial assessment of the post-retirement medical plan benefit obligation resulted in a reduction of costs of $241k.

Fixed Assets (Actual - $295,792 under budget)
By accelerating capital expenditures in late 2013 there was a decrease in the need for capital expenditures in 2014. Facility reconfigurations were pushed into a future date in order to offset the 2014 excess costs in other areas.

Change in Assets and Year-End
MRO was under budget by $131k as explained above, resulting in a $131k increase in Working Capital.

MRO had no non-statutory activities in 2104; therefore, there were no allocations of costs between statutory and non-statutory activities and no statutory funds were used for non-statutory purposes.

Section A — Statutory Programs

1. Reliability Standards, Organization Registration and Certification Program

RELIABILITY STANDARDS, REGISTRATION AND CERTIFICATION	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	429,997	429,997	-	0.00%
Penalty Sanctions	5,361	5,361	-	0.00%
Total ERO Funding	**$ 435,358**	**$ 435,358**	$ -	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	435,358	435,358	-	0.00%
Expenses				
Personnel Expenses				
Salaries	167,659	175,057	(7,398)	-4.23%
Payroll Taxes	8,471	9,981	(1,510)	-15.13%
Employee Benefits	10,291	12,129	(1,838)	-15.15%
Savings & Retirement	29,334	34,167	(4,833)	-14.15%
Total Personnel Expenses	215,755	231,334	(15,579)	-6.73%
Meeting Expenses				
Meetings	1,276	4,000	(2,724)	-68.10%
Travel	20,320	28,900	(8,580)	-29.69%
Conference Calls	41	-	41	
Total Meeting Expenses	21,637	32,900	(11,263)	-34.23%
Operating Expenses				
Consultants & Contracts	12,300	12,000	300	2.50%
Rent & Improvements	-	-	-	
Office Costs	4,638	3,194	1,444	45.21%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	16,938	15,194	1,744	11.48%
Indirect Expenses	161,298	159,877	1,421	0.89%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	415,628	439,305	(23,677)	-5.39%
Change in Assets (A - B)	19,730	(3,947)	23,677	-599.88%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
(Inc)Dec in Fixed Assets	$ -	$ -	$ -	
Allocation of Fixed Assets	(14,962)	(3,947)	(11,015)	279.08%
Total Inc(Dec) in Fixed Assets (C)	(14,962)	(3,947)	(11,015)	279.08%
TOTAL BUDGET (B + C)	**400,665**	**435,358**	(34,693)	**-7.97%**
Change in Working Capital (A-B-C)	**(34,693)**	**-**	**(34,693)**	
FTEs	**1.1**	**1.2**	(0.1)	**-6.84%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Meeting Expenses

- Back-up service for conferencing not budgeted for.

Other Non-Operating Expenses

N/A

Fixed Asset Additions

Total actual fixed costs were under budget; therefore, there were less asset costs than budgeted allocated to this program.

2. Compliance Monitoring and Enforcement Program (CMEP)

COMPLIANCE MONITORING AND ENFORCEMENT	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	6,600,177	6,600,177	-	0.00%
Penalty Sanctions	97,415	97,415	-	0.00%
Total ERO Funding	**$ 6,697,592**	**$ 6,697,592**	$ -	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	6,697,592	6,697,592	-	0.00%
Expenses				
Personnel Expenses				
Salaries	2,585,820	2,631,450	(45,630)	-1.73%
Payroll Taxes	164,399	179,885	(15,486)	-8.61%
Employee Benefits	192,815	222,055	(29,240)	-13.17%
Savings & Retirement	347,876	461,742	(113,866)	-24.66%
Total Personnel Expenses	3,290,910	3,495,132	(204,222)	-5.84%
Meeting Expenses				
Meetings	2,163	5,500	(3,337)	-60.67%
Travel	119,319	137,000	(17,681)	-12.91%
Conference Calls	-	-	-	
Total Meeting Expenses	121,482	142,500	(21,018)	-14.75%
Operating Expenses				
Consultants & Contracts	114,073	127,000	(12,927)	-10.18%
Rent & Improvements	-	-	-	
Office Costs	66,882	94,560	(27,678)	-29.27%
Professional Services	-	5,000	(5,000)	-100.00%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	180,955	226,560	(45,605)	-20.13%
Indirect Expenses	2,928,513	2,905,124	23,389	0.81%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	6,521,860	6,769,316	(247,456)	-3.66%
Change in Assets (A - B)	175,732	(71,724)	247,456	-345.01%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
(Inc)Dec in Fixed Assets	$ -	$ -	$ -	
Allocation of Fixed Assets	(271,653)	(71,723)	(199,930)	278.75%
Total Inc(Dec) in Fixed Assets (C)	(271,653)	(71,723)	(199,930)	278.75%
TOTAL BUDGET (B + C)	**6,250,207**	**6,697,593**	(447,386)	**-6.68%**
Change in Working Capital (A-B-C)	**(447,385)**	**1**	**(447,386)**	-44738606.03%
FTEs	**19.8**	**21.3**	(1.5)	**-6.91%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Personnel Expenses

- Employee Benefits: Medical premiums were budgeted at a 5% increase but the 2014 actuals came in flat.
- Savings & Retirement: Annual post-retirement adjustment reduced the net periodic cost for 2014 provided by third party advisors.

Meeting Expenses

- Reduced travel costs due to shorter duration of on-site audits and participation by fewer auditors; in-person participation in fewer working group meetings; and attendance at fewer NERC Board of Trustee meetings.

Operating Expenses

Consultants and Contracts

- Multiple regions shared the cost of changes required in the information tracking applications which resulted in lower costs to MRO. By sharing these costs among the regions, each region benefited from the economy of scale.

Office Costs

- Less office costs related to training. Training costs were lower than budget partially due to dollars being budgeted in the discretionary tuition reimbursement program that were not pursued by staff in 2014. Additionally, staff is encouraged if possible to take training locally. Finally, when staff has more than one certification or required CEUs in more than one area, they are strongly encouraged to seek training opportunities that can be applied to more than one area.

Other Non-Operating Expenses

N/A

Fixed Asset Additions

Total actual fixed costs were under budget; therefore, there were less asset costs than budgeted allocated to this program.

3. Reliability Assessment and Performance Analysis Program

RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS Includes Event Analysis	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	2,164,689	2,164,689	-	0.00%
Penalty Sanctions	29,738	29,738	-	0.00%
Total ERO Funding	**$ 2,194,427**	**$ 2,194,427**	$ -	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	2,194,427	2,194,427	-	0.00%
Expenses				
Personnel Expenses				
Salaries	962,732	793,111	169,621	21.39%
Payroll Taxes	60,781	53,718	7,063	13.15%
Employee Benefits	76,070	68,241	7,829	11.47%
Savings & Retirement	190,590	170,310	20,280	11.91%
Total Personnel Expenses	1,290,173	1,085,380	204,793	18.87%
Meeting Expenses				
Meetings	6,280	5,500	780	14.18%
Travel	196,854	81,000	115,854	143.03%
Conference Calls	167	-	167	
Total Meeting Expenses	203,301	86,500	116,801	135.03%
Operating Expenses				
Consultants & Contracts	90,661	126,700	(36,039)	-28.44%
Rent & Improvements	-	-	-	
Office Costs	11,046	30,900	(19,854)	-64.25%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	101,707	157,600	(55,893)	-35.47%
Indirect Expenses	1,117,245	886,842	230,403	25.98%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	2,712,426	2,216,322	496,104	22.38%
Change in Assets (A - B)	(517,999)	(21,895)	(496,104)	2265.83%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
(Inc)Dec in Fixed Assets	$ -	$ -	$ -	
Allocation of Fixed Assets	(103,637)	(21,895)	(81,742)	373.34%
Total Inc(Dec) in Fixed Assets (C)	(103,637)	(21,895)	(81,742)	373.34%
TOTAL BUDGET (B + C)	**2,608,789**	**2,194,427**	414,362	**18.88%**
Change in Working Capital (A-B-C)	**414,362**	-	**414,362**	
FTEs	**7.6**	**6.5**	1.1	**16.33%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Personnel Expenses

- More personnel costs associated with the event analysis function than what was budgeted. The additional costs in this program were offset in the other program areas. The variance also reflects the attendance at the NERC level activities previously charged under program Forums (1100) as explained below under Meeting Expenses.

Meeting Expenses

- Due to the increased number of activities in this area there was more travel than anticipated. Activities included but were not limited to BES, RAPA, and Event Analysis meetings at the NERC level. MRO staff attendance at NERC level activities that was originally budgeted under program Forums (1100) was charged to RAPA after 06/30/2013 based on the treatment by the other regions. This impacted the 2014 actual to budget variance since the 2014 BP&B was MRO Board approved in June 2013.
- Back-up service for conferencing was not budgeted for.

Operating Expenses

Consultants and Contracts

- RAPA has three contracts that are budgeted based on an estimated number of required hours; actual hours can fluctuate greatly. Fewer hours were required under these contracts in 2014 than was anticipated.

Office Costs

- Dropped NAESB membership because the benefits of membership did not justify the costs.

Indirect Expenses

- Reflects the higher than budgeted FTE since the indirect expenses are spread on a FTE basis.

Other Non-Operating Expenses

N/A

Fixed Asset Additions

- Total actual fixed costs were under budget; therefore, there were less asset costs than budgeted allocated to this program.

4. Training, Education, and Operator Certification Program

TRAINING, EDUCATION and OPERATOR CERTIFICATION	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	330,159	330,159	-	0.00%
Penalty Sanctions	2,978	2,978	-	0.00%
Total ERO Funding	**$ 333,137**	**$ 333,137**	$ -	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	333,137	333,137	-	0.00%
Expenses				
Personnel Expenses				
Salaries	133,982	135,804	(1,822)	-1.34%
Payroll Taxes	7,278	6,128	1,150	18.77%
Employee Benefits	5,445	6,856	(1,411)	-20.58%
Savings & Retirement	20,740	22,921	(2,181)	-9.52%
Total Personnel Expenses	167,445	171,709	(4,264)	-2.48%
Meetings	45,134	49,000	(3,866)	-7.89%
Travel	16,298	20,800	(4,502)	-21.64%
Conference Calls	-	-	-	
Total Meeting Expenses	61,432	69,800	(8,368)	-11.99%
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	1,196	5,000	(3,804)	-76.08%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	1,196	5,000	(3,804)	-76.08%
Indirect Expenses	41,434	88,821	(47,387)	-53.35%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	271,507	335,330	(63,823)	-19.03%
Change in Assets (A - B)	61,630	(2,193)	63,823	-2910.29%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
(Inc)Dec in Fixed Assets	$ -	$ -	$ -	
Allocation of Fixed Assets	(3,843)	(2,193)	(1,650)	75.26%
Total Inc(Dec) in Fixed Assets (C)	(3,843)	(2,193)	(1,650)	75.26%
TOTAL BUDGET (B + C)	**267,664**	**333,137**	(65,473)	**-19.65%**
Change in Working Capital (A-B-C)	**(65,473)**	**-**	**(65,473)**	
FTEs	**0.28**	**0.65**	(0.4)	**-56.92%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Indirect Expenses

- Total actual indirect costs were under budget, therefore fewer indirect costs than budgeted allocated to this program.

Other Non-Operating Expenses

N/A

5. Situation Awareness and Infrastructure Security Program

SITUATION AWARENESS and INFRASTRUCTURE SECURITY (Includes Critical Infrastructure Protection)	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	83,275	83,275	-	0.00%
Penalty Sanctions	1,008	1,008	-	0.00%
Total ERO Funding	**$ 84,283**	**$ 84,283**	$ -	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	84,283	84,283	-	0.00%
Expenses				
Personnel Expenses				
Salaries	30,409	39,332	(8,923)	-22.69%
Payroll Taxes	2,163	2,173	(10)	-0.46%
Employee Benefits	2,675	2,320	355	15.30%
Savings & Retirement	6,668	6,138	530	8.63%
Total Personnel Expenses	41,915	49,963	(8,048)	-16.11%
Meeting Expenses				
Meetings	150	-	150	
Travel	17,698	-	17,698	
Conference Calls	-	-	-	
Total Meeting Expenses	17,848	-	17,848	
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	5,531	5,000	531	10.62%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	5,531	5,000	531	10.62%
Indirect Expenses	23,677	30,062	(6,385)	-21.24%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	88,971	85,025	3,946	4.64%
Change in Assets (A - B)	(4,688)	(742)	(3,946)	531.77%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
(Inc)Dec in Fixed Assets	$ -	$ -	$ -	
Allocation of Fixed Assets	(2,196)	(742)	(1,454)	196.00%
Total Inc(Dec) in Fixed Assets (C)	(2,196)	(742)	(1,454)	196.00%
TOTAL BUDGET (B + C)	**86,774**	**84,283**	2,491	**2.96%**
Change in Working Capital (A-B-C)	**2,491**	**-**	**2,491**	
FTEs	**0.16**	**0.22**	**(0.06)**	**-27.27%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Meeting Expenses

- One staff and two MRO representatives attended NERC CIPC quarterly meetings. These costs were not budgeted for in 2014.

Other Non-Operating Expenses

N/A

6. Administrative Services

Methodology for Allocation of Administrative Services Expenses to Programs

All expenses for the Administrative Services Programs, referred to as indirect expenses, are allocated to the delegated program areas based on their respective number of FTEs. This allocation provides improved financial perspective for the delegated functions.

6a. Technical Committees and Member Forums

MEMBER FORUMS	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	-		-	
Penalty Sanctions	-		-	
Total ERO Funding	$ -	$ -	$ -	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	-	-	-	
Expenses				
Personnel Expenses				
Salaries	-	286,447	(286,447)	-100.00%
Payroll Taxes	-	15,986	(15,986)	-100.00%
Employee Benefits	-	15,715	(15,715)	-100.00%
Savings & Retirement	-	58,368	(58,368)	-100.00%
Total Personnel Expenses	-	376,516	(376,516)	-100.00%
Meeting Expenses				
Meetings	-	-	-	
Travel	-	228,700	(228,700)	-100.00%
Conference Calls	-	-	-	
Total Meeting Expenses	-	228,700	(228,700)	-100.00%
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	-	-	-	
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	-	-	-	
Indirect Expenses	-	(605,216)	605,216	-100.00%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	-	-	-	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
(Inc)Dec in Fixed Assets	$ -	$ -	$ -	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	-	-	-	
Change in Working Capital (A-B-C)	-	-	-	
FTEs	-	**1.7**	(1.7)	**-100.00%**

Eliminated 07/01/2013 to conform to how other regions are recording NERC participation. All other regions and NERC record costs in the program of the participant. We will track NERC time separately. This impacted the 2014 actual versus budget variance since the 2014 BP&B was MRO Board approved in June 2013.

Personnel Expenses

- Actuals are substantially below budget because as of 7/1/2013 MRO stopped recording costs to Member Forums. Please see above comment for details.

Meeting Expenses

- Actuals are substantially below budget because as of 7/1/2013 MRO stopped recording costs to Member Forums. Please see above comment for details.

Operating Expenses

- Actuals are substantially below budget because as of 7/1/2013 MRO stopped recording costs to Member Forums. Please see above comment for details.

Indirect Expenses

- Actuals are substantially below budget because as of 7/1/2013 MRO stopped recording costs to Member Forums. Please see above comment for details.

6b. General and Administrative

GENERAL and ADMINISTRATIVE	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	(866,855)	(866,855)	-	0.00%
Penalty Sanctions	-		-	
Total ERO Funding	**$ (866,855)**	**$ (866,855)**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	(866,855)	(866,855)	-	0.00%
Expenses				
Personnel Expenses				
Salaries	363,588	289,381	74,207	25.64%
Payroll Taxes	17,866	15,884	1,982	12.48%
Employee Benefits	19,268	14,661	4,607	31.42%
Savings & Retirement	70,106	49,575	20,531	41.41%
Total Personnel Expenses	470,828	369,501	101,327	27.42%
Meeting Expenses				
Meetings	23,433	35,864	(12,431)	-34.66%
Travel	99,701	83,000	16,701	20.12%
Conference Calls	43	-	43	
Total Meeting Expenses	123,177	118,864	4,313	3.63%
Operating Expenses				
Consultants & Contracts	47,748	40,000	7,748	19.37%
Rent & Improvements	-	-	-	
Office Costs	63,708	64,000	(292)	-0.46%
Professional Services	63,000	100,000	(37,000)	-37.00%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	174,456	204,000	(29,544)	-14.48%
Indirect Expenses	(768,461)	(692,365)	(76,096)	10.99%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	(866,855)	(866,855)	-	0.00%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
(Inc)Dec in Fixed Assets	$ -	$ -	$ -	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	**-**	**-**	-	
Change in Working Capital (A-B-C)	**866,855**	**866,855**	**-**	0.00%
FTEs	**1.7**	**1.9**	(0.2)	**-10.82%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Personnel Expenses

- MRO staff attendance at the Board of Trustees that was budgeted under program Forums (1100) was charged to G&A after 06/30/2013 based on the treatment by the other regions. This impacted the 2014 actual versus budget variance since the 2014 BP&B was MRO Board approved in June 2013.

Meeting Expenses

- Approximately the same number of meetings at a much lower cost due to hosting at MRO's facility. Savings resulted from eliminating meeting room and audio visual rental costs as well as lowering catering costs.
- The BOT travel that was budgeted under program Forums (1100) was charged to G&A after 06/30/2013 based on the treatment by the other regions.
- Back-up service for conferencing was not budgeted for.

Operating Expenses

Professional Services

- Dollars were budgeted for the Independent Board members whose activities fluctuate based on need. In 2014, the Independent Board members were required to spend less time than was anticipated.

Indirect Expenses

- Expenses related to indirect programs have been allocated proportionately based on FTE count to the direct programs.

Other Non-Operating Expenses

N/A

6c. Legal and Regulatory

LEGAL and REGULATORY	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments			-	
Penalty Sanctions			-	
Total ERO Funding	$ -	$ -	$ -	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	-	-	-	
Expenses				
Personnel Expenses				
Salaries	215,792	173,407	42,385	24.44%
Payroll Taxes	11,759	8,754	3,005	34.33%
Employee Benefits	1,815	2,848	(1,033)	-36.27%
Savings & Retirement	29,890	28,163	1,727	6.13%
Total Personnel Expenses	259,256	213,172	46,084	21.62%
Meeting Expenses				
Meetings	-	150	(150)	-100.00%
Travel	16,903	12,500	4,403	35.22%
Conference Calls	-	-	-	
Total Meeting Expenses	16,903	12,650	4,253	33.62%
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	5,098	6,000	(902)	-15.03%
Professional Services	5,854	40,000	(34,146)	-85.37%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	10,952	46,000	(35,048)	-76.19%
Indirect Expenses	(287,111)	(271,822)	(15,289)	5.62%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	-	-	-	
Fixed Assets				
Depreciation	0.00	0.00	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
(Inc)Dec in Fixed Assets	$ -	$ -	$ -	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	-	-	-	
Change in Working Capital (A-B-C)	-	-	-	
FTEs	**1.2**	**0.9**	0.3	**33.33%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Personnel Expenses

- MRO staff attendance at the Board of Trustees that was budgeted under program Forums (1100) was charged to Legal after 06/30/2013 based on the treatment by the other regions. This impacted the 2014 since the 2014 BP&B was MRO Board approved June 2013.

Operating Expenses

Professional Services

- External professional services were difficult to trend because of the nature of the costs. Normally these costs are incurred in response to a specific situation that has developed. There was less need for external professional services in 2014 than had been anticipated.

Other Non-Operating Expenses

N/A

6d. Information Technology

INFORMATION TECHNOLOGY		2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding					
	ERO Funding				
	Assessments			-	
	Penalty Sanctions			-	
	Total ERO Funding	$ -	$ -	$ -	
	Federal Grants	-	-	-	
	Membership Fees	-	-	-	
	Testing	-	-	-	
	Services & Software	-	-	-	
	Workshop Fees	-	-	-	
	Interest	-	-	-	
	Miscellaneous	-	-	-	
Total Funding (A)		-	-	-	
Expenses					
	Personnel Expenses				
	Salaries	391,114	305,832	85,282	27.89%
	Payroll Taxes	29,210	23,186	6,024	25.98%
	Employee Benefits	41,935	33,013	8,922	27.03%
	Savings & Retirement	82,144	66,171	15,973	24.14%
	Total Personnel Expenses	544,403	428,202	116,201	27.14%
	Meeting Expenses				
	Meetings	795	-	795	
	Travel	843	4,000	(3,157)	-78.93%
	Conference Calls	-	-	-	
	Total Meeting Expenses	1,638	4,000	(2,362)	-59.05%
	Operating Expenses				
	Consultants & Contracts	528,357	212,400	315,957	148.76%
	Rent & Improvements	-	-	-	
	Office Costs	185,725	179,050	6,675	3.73%
	Professional Services	-	-	-	
	Miscellaneous	-	-	-	
	Depreciation	477,763	471,000	6,763	1.44%
	Total Operating Expenses	1,191,845	862,450	329,395	38.19%
	Indirect Expenses	(1,737,886)	(1,294,652)	(443,234)	34.24%
	Other Non-Operating Expenses	-	-	-	
Total Expenses (B)		-	-	-	
Change in Assets (A - B)		-	-	-	
Fixed Assets					
	Depreciation	(477,763.00)	(471,000.00)	(6,763)	1.44%
	Computer & Software CapEx	67,864	320,500	(252,636)	-78.83%
	Furniture & Fixtures CapEx	-	-	-	
	Equipment CapEx	-	-	-	
	Leasehold Improvements	-	-	-	
	(Inc)Dec in Fixed Assets	$ (409,899)	$ (150,500)	$ (259,399)	
	Allocation of Fixed Assets	409,899	150,500	259,399	172.36%
Total Inc(Dec) in Fixed Assets ©		-	-	-	
TOTAL BUDGET (B + C)		-	-	-	
Change in Working Capital (A-B-C)		-	-	-	
FTEs		**4.2**	**3.1**	1.1	**35.46%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Personnel Expenses

- Senior management time charged to the IT area was greater than budgeted because MRO began several significant projects: SharePoint, Website and Lync.

Operating Expenses

Consultants and Contracts

- Unbudgeted upgrade of MRO's website and implementation of SharePoint.

Indirect Expenses

- Expenses related to indirect programs have been allocated proportionately based on FTE count to the direct programs.

Other Non-Operating Expenses

N/A

Fixed Asset Additions

- By accelerating capital expenditures in late 2013 there was a decrease in the need for capital expenditures in 2014.
- Total actual fixed costs were under budget; therefore, there were less asset costs than budgeted allocated to this program.

6e. Human Resources

Human Resources costs are included in Finance and Accounting.

6f. Human Resources, Finance, and Accounting

HUMAN RESOURCES, FINANCE and ACCOUNTING	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	-		-	
Penalty Sanctions	-		-	
Total ERO Funding	$ -	$ -	$ -	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	-	-	-	
Expenses				
Personnel Expenses				
Salaries	337,761	348,717	(10,956)	-3.14%
Payroll Taxes	23,095	23,459	(364)	-1.55%
Employee Benefits	31,650	34,384	(2,734)	-7.95%
Savings & Retirement	59,454	71,365	(11,911)	-16.69%
Total Personnel Expenses	451,960	477,925	(25,965)	-5.43%
Meeting Expenses				
Meetings	-	500	(500)	-100.00%
Travel	4,922	3,000	1,922	64.07%
Conference Calls	-	-	-	
Total Meeting Expenses	4,922	3,500	1,422	40.63%
Operating Expenses				
Consultants & Contracts	136,056	25,000	111,056	444.22%
Rent & Improvements	492,489	524,827	(32,338)	-6.16%
Office Costs	106,544	115,420	(8,876)	-7.69%
Professional Services	45,116	60,000	(14,884)	-24.81%
Miscellaneous	-	-	-	
Depreciation	167	-	167	
Total Operating Expenses	780,372	725,247	55,125	7.60%
Indirect Expenses	(1,478,708)	(1,206,672)	(272,036)	22.54%
Other Non-Operating Expenses	241,454	-	241,454	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	-	-	-	
Fixed Assets				
Depreciation	(167)	-	(167)	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	6,844	-	6,844	
Equipment CapEx	-	-	-	
Leasehold Improvements	6,930	50,000	(43,070)	-86.14%
(Inc)Dec in Fixed Assets	13,607	50,000	(36,393)	
Allocation of Fixed Assets	(13,607)	(50,000)	36,393	-72.79%
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	-	-	-	
Change in Working Capital (A-B-C)	-	-	-	
FTEs	**3.5**	**3.3**	0.2	**6.36%**

Explanation of Variance greater than $10,000 and 10 percent; as well as expenses not budgeted

Personnel Expenses

- Annual post-retirement adjustment reduced the net periodic cost for 2014 provided by third party advisors.

Operating Expenses

Consultants and Contracts

- MRO used outside recruiters for certain positions.

Professional Services

- The IT audit scope was charged through the IT program; however, this had been budgeted for in the Finance and Accounting program.

Indirect Expenses

- Expenses related to indirect programs have been allocated proportionately based on FTE count to the direct programs.

Other Non-Operating Expenses

- Trending in higher medical premiums and a 2014 new mortality rate increasing life expectancy increased the required balance for 2014 provided by third party advisors.

Fixed Asset Additions

- Facility reconfigurations were pushed into a future date in order to offset the 2014 excess costs in consultants and contracts.
- Total actual fixed costs were under budget; therefore, there were less asset costs than budgeted allocated to this program.

Section B — Supplemental Financial Information

Statement of Activities and Capital Expenditures by Program 2014 Actual	Total	Statutory Total	Non-Statutory Total	Functions in Delegation Agreement: Statutory Total	Reliability Standards (Section 300)	Compliance and Organization Registration and Certification (Section 400 & 500)	Reliability Assessment and Performance Analysis (Section 800)	Training and Education (Section 600 & 900)	Situation Awareness and Infrastructure Security (Section 1000)	Committee and Member Forums	General and Administrative	Legal and Regulatory	Information Technology	Human Resources	Accounting and Finance
Funding															
ERO Funding															
NERC Assessments	8,741,442	8,741,442	-	8,741,442	429,997	6,600,177	2,164,689	330,159	83,275		(866,855)				
Penalty Sanctions	136,500	136,500	-	136,500	5,361	97,415	29,738	2,978	1,008						
Total NERC Funding	**8,877,942**	**8,877,942**	**-**	**8,877,942**	**435,358**	**6,697,592**	**2,194,427**	**333,137**	**84,283**	**-**	**(866,855)**	**-**	**-**	**-**	**-**
Membership Dues	-	-	-							-					
Testing Fees	-	-	-												
Services & Software	-	-	-												
Workshops	-	-	-												
Interest	-	-	-												
Miscellaneous	-	-	-												
Total Funding (A)	**8,877,942**	**8,877,942**	**-**	**8,877,942**	**435,358**	**6,697,592**	**2,194,427**	**333,137**	**84,283**	**-**	**(866,855)**	**-**	**-**	**-**	**-**
Expenses															
Personnel Expenses															
Salaries	5,188,857	5,188,857	-	5,188,857	167,659	2,585,820	962,732	133,982	30,409	-	363,588	215,792	391,114	-	337,761
Payroll Taxes	325,022	325,022	-	325,022	8,471	164,399	60,781	7,278	2,163	-	17,866	11,759	29,210	-	23,095
Benefits	381,964	381,964	-	381,964	10,291	192,815	76,070	5,445	2,675	-	19,268	1,815	41,935	-	31,650
Retirement Costs	836,802	836,802	-	836,802	29,334	347,876	190,590	20,740	6,668	-	70,106	29,890	82,144	-	59,454
Total Personnel Expenses	6,732,645	6,732,645	-	6,732,645	215,755	3,290,910	1,290,173	167,445	41,915	-	470,828	259,256	544,403	-	451,960
Meeting Expenses															
Meetings	79,231	79,231	-	79,231	1,276	2,163	6,280	45,134	150	-	23,433	-	795	-	-
Travel	492,858	492,858	-	492,858	20,320	119,319	196,854	16,298	17,698	-	99,701	16,903	843	-	4,922
Conference Calls	251	251	-	251	41	-	167	-	-	-	43	-	-	-	-
Total Meeting Expenses	572,340	572,340	-	572,340	21,637	121,482	203,301	61,432	17,848	-	123,177	16,903	1,638	-	4,922
Operating Expenses															
Consultants & Contracts	929,195	929,195	-	929,195	12,300	114,073	90,661	-	-	-	47,748	-	528,357	-	136,056
Office Rent	492,489	492,489	-	492,489	-	-	-	-	-	-	-	-	-	-	492,489
Office Costs	450,368	450,368	-	450,368	4,638	66,882	11,046	1,196	5,531	-	63,708	5,098	185,725	-	106,544
Professional Services	113,970	113,970	-	113,970	-	-	-	-	-	-	63,000	5,854	-	-	45,116
Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation	477,930	477,930	-	477,930	-	-	-	-	-	-	-	-	477,763	-	167
Total Operating Expenses	2,463,952	2,463,952	-	2,463,952	16,938	180,955	101,707	1,196	5,531	-	174,456	10,952	1,191,845	-	780,372
Total Direct Expenses	**9,768,937**	**9,768,937**	**-**	**9,768,937**	**254,330**	**3,593,347**	**1,595,181**	**230,073**	**65,294**	**-**	**768,461**	**287,111**	**1,737,886**	**-**	**1,237,254**
Indirect Expenses	-	-	-	-	161,298	2,928,513	1,117,245	41,434	23,677	-	(768,461)	(287,111)	(1,737,886)	-	(1,478,708)
Other Non-Operating Expenses	**241,454**	**241,454**	**-**	**241,454**							-	-	-	-	241,454
Total Expenses (B)	**10,010,391**	**10,010,391**	**-**	**10,010,391**	**415,628**	**6,521,860**	**2,712,426**	**271,507**	**88,971**	**-**	**-**	**-**	**-**	**-**	**-**
Change in Assets	**(1,132,449)**	**(1,132,449)**	**-**	**(1,132,449)**	**19,730**	**175,732**	**(517,999)**	**61,630**	**(4,688)**	**-**	**(866,855)**	**-**	**-**	**-**	**-**
Fixed Assets															
Depreciation	(477,930)	(477,930)	-	(477,930)	-	-	-	-	-	-	-	-	(477,763)	-	(167)
Computer & Software CapEx	67,864	67,864	-	67,864									67,864		-
Furniture & Fixtures CapEx	6,844	6,844	-	6,844											6,844
Equipment CapEx	-	-	-	-											-
Leasehold Improvements	6,930	6,930	-	6,930											6,930
Allocation of Fixed Assets	0	0	-	0	(14,962)	(271,653)	(103,637)	(3,843)	(2,196)		-	-	409,899	-	(13,607)
Inc(Dec) in Fixed Assets (C)	**(396,292)**	**(396,292)**	**-**	**(396,292)**	**(14,962)**	**(271,653)**	**(103,637)**	**(3,843)**	**(2,196)**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL BUDGET (=B + C)	**9,614,099**	**9,614,099**	**-**	**9,614,099**	**400,665**	**6,250,207**	**2,608,789**	**267,664**	**86,774**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**(736,157)**	**(736,157)**	**-**	**(736,157)**	**34,693**	**447,385**	**(414,362)**	**65,473**	**(2,491)**	**-**	**(866,855)**	**-**	**-**	**-**	**-**
FTEs	**39.59**	**39.59**	**-**	**39.59**	**1.09**	**19.79**	**7.55**	**0.28**	**0.16**	**-**	1.73	1.24	4.24	-	3.51

MIDWEST RELIABILITY ORGANIZATION

Saint Paul, Minnesota

FINANCIAL STATEMENTS

Including Independent Auditors' Report

As of and for the Years Ended December 31, 2014 and 2013

MIDWEST RELIABILITY ORGANIZATION

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BAKER TILLY

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Minneapolis, MN 55402-4661
tel 612 876 4500
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INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Members
Midwest Reliability Organization
Saint Paul, Minnesota

We have audited the accompanying financial statements of Midwest Reliability Organization (the "Organization"), which comprise the statements of financial position as of December 31, 2014 and 2013, and the related statements of activities and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Organization as of December 31, 2014 and 2013, and the changes in its net assets and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Baker Tilly Virchow Krause, LLP

Minneapolis, Minnesota
April 2, 2015

An Affirmative Action Equal Opportunity Employer

MIDWEST RELIABILITY ORGANIZATION

STATEMENTS OF FINANCIAL POSITION
As of December 31, 2014 and 2013

	2014	2013
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 3,655,712	$ 3,739,704
Restricted cash	395,044	136,516
Accounts receivable	6,762	34,726
Prepaid expenses	188,536	263,633
Total Current Assets	4,246,054	4,174,579
PROPERTY, IMPROVEMENTS AND EQUIPMENT, NET	877,691	1,194,569
OTHER ASSETS		
Restricted cash - non-current	95,008	320,013
Security Deposit - non-current	39,858	39,858
Capitalized software costs, net of accumulated amortization of $522,839 and $439,510, respectively	106,808	186,220
TOTAL ASSETS	$ 5,365,419	$ 5,915,239
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable - trade	$ 215,943	$ 207,901
Accrued liabilities	733,084	638,307
Retirement plan contribution	453,228	407,436
Deferred assessments	395,044	136,512
Total Current Liabilities	1,797,299	1,390,156
OTHER LIABILITIES		
Postretirement medical benefit obligation	410,296	153,171
Deferred assessments - non-current	95,008	320,013
Deferred rent - non-current	452,941	309,572
Total Liabilities	2,755,544	2,172,912
MEMBERS' EQUITY	2,609,875	3,742,327
TOTAL LIABILITIES AND MEMBERS' EQUITY	$ 5,365,419	$ 5,915,239

See accompanying notes to financial statements.

MIDWEST RELIABILITY ORGANIZATION

STATEMENTS OF OPERATIONS AND MEMBERS' EQUITY
For the Years Ended December 31, 2014 and 2013

	2014	2013
REVENUE		
Assessments	$ 8,741,442	$ 9,098,927
Penalty sanctions	136,500	14,000
Total Revenue	8,877,942	9,112,927
EXPENSES		
Personnel expenses		
Salaries	5,188,857	4,760,887
Payroll taxes	325,023	310,791
Employee benefits	381,964	380,894
Retirement benefits	836,804	724,304
Total personnel expenses	6,732,648	6,176,876
Meeting expenses		
Conference calls	251	15,142
Meetings	79,322	91,601
Travel	492,766	475,020
Total meeting expenses	572,339	581,763
Operating expenses		
Building rent and facilities	492,489	487,109
Consulting	929,197	490,643
Office costs	928,298	853,446
Professional services	113,969	147,338
Total operating expenses	2,463,953	1,978,536
Total Expenses	9,768,940	8,737,175
CHANGE IN MEMBERS' EQUITY BEFORE POSTRETIREMENT RELATED CHANGES	(890,998)	375,752
POSTRETIREMENT-RELATED CHANGES		
Postretirement medical benefit obligation changes other than net periodic cost	241,454	(194,304)
CHANGE IN MEMBERS' EQUITY	(1,132,452)	570,056
MEMBERS' EQUITY - Beginning of Year	3,742,327	3,172,271
MEMBERS' EQUITY - END OF YEAR	$ 2,609,875	$ 3,742,327

See accompanying notes to financial statements.

MIDWEST RELIABILITY ORGANIZATION

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014 and 2013

	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Change in members' equity	$ (1,132,452)	$ 570,056
Adjustments to reconcile excess of revenues over expenses to net cash provided by operating activities		
Depreciation	394,601	354,848
Software amortization	83,329	55,411
Change in assets and liabilities:		
Accounts receivable	27,964	156,640
Prepaid expenses	75,097	(63,357)
Accounts payable - trade	47,561	(128,156)
Accrued liabilities	94,777	57,940
Retirement plan contribution	45,792	49,636
Deferred assessments	33,527	338,520
Deferred rent	143,369	187,596
Postretirement medical benefit obligation	257,125	(194,163)
Change from Operating Activities	70,690	1,384,971
CASH FLOWS FROM INVESTING ACTIVITIES		
Change in restricted cash	(33,523)	(338,524)
Purchases of property, improvements and equipment and software	(121,159)	(497,575)
Change from Investing Activities	(154,682)	(836,099)
Net Change in Cash and Cash Equivalents	(83,992)	548,872
CASH AND CASH EQUIVALENTS - BEGINNING OF YEAR	3,739,704	3,190,832
CASH AND CASH EQUIVALENTS - END OF YEAR	$ 3,655,712	$ 3,739,704
SUPPLEMENTAL CASH FLOW DISCLOSURE		
Equipment and software additions included in accounts payable	$ 14,275	$ 53,795

See accompanying notes to financial statements.

NOTE 1 - SIGNIFICANT ACCOUNTING POLICIES

Services

Midwest Reliability Organization (or the "Organization") is a nonprofit organization dedicated to ensuring the reliability of the bulk power system in the north-central part of North America. The Organization is a Regional Entity under the Energy Policy Act of 2005 (United States) and operates under delegated authority from the Federal Energy Regulatory Commission (FERC) via a delegation agreement with the North American Reliability Corporation. Additionally, the Organization operates in the provinces of Saskatchewan and Manitoba through other agreements. The primary focus of the Organization is ensuring compliance with reliability standards utilizing open, fair processes in the public interest and providing assessments on bulk power system reliability. In addition to the Board of Directors, Midwest Reliability Organization has formed four standing committees: Compliance Committee, Planning Committee, Operating Committee and the Standards Committee. The Board of Directors has four committees: Finance and Audit Committee, Governance and Personnel Committee, Dispute Resolution Committee and Hearing Body Committee.

Cash and Cash Equivalents

The Organization considers all highly liquid investments with original maturities of three months or less to be cash equivalents. Cash and cash equivalents are held by one financial institution, Wells Fargo, in three accounts. Escrowed amounts resulting from penalties assessed and collected in the United States are segregated into a separate account and reported as restricted cash on the statement of financial position.

Receivables

Receivables, if any, result primarily from assessments related to load serving entities (members and nonmembers). No allowance for doubtful accounts is recorded based on historical experience and management's evaluation of receivables. Bad debts are expensed when deemed uncollectible. Receivables are generally unsecured.

Property, Improvements and Equipment

Property, improvements and equipment are stated at cost less accumulated depreciation and amortization. Significant additions or improvements exceeding $3,000 are capitalized for the years ended December 31, 2014 and 2013, while expenditures for maintenance and repairs are charged to operations as incurred. Depreciation is recorded using the straight-line method over the estimated useful lives of the assets, ranging from three to seven years. Leasehold improvements are amortized using the straight-line method over the shorter of the estimated useful life or the remaining lease term. The cost and related accumulated depreciation of assets sold or disposed of are removed from the accounts, and the resulting gain or loss is included in operations.

Capitalized Software Costs

The Organization capitalizes software development costs incurred and purchased software in upgrading computer software used internally to serve its members. The Organization begins capitalization of these costs after technological feasibility has been determined. The capitalized software, once placed in service, is amortized on the straight-line method over its estimated useful life of three years. Accumulated amortization totaled $522,839 and $439,510 for the years ended December 31, 2014 and 2013, respectively. Amortization expense totaled $83,329 and $55,411 for the years ended December 31, 2014 and 2013, respectively.

NOTE 1 - SIGNIFICANT ACCOUNTING POLICIES (Continued)

Deferred Assessments

Deferred assessments represents penalty assessments paid by load-serving entities, which will be used to offset budget allocations received from NERC.

Tax Status

The Internal Revenue Service has determined that the Organization is exempt from federal income taxes under Section 501(c)(6) of the Internal Revenue Code. They are also exempt from state income taxes. However, any unrelated business income may be subject to taxation.

The Organization follows the accounting standards for contingencies in evaluating uncertain tax positions. This guidance prescribes recognition threshold principles for the financial statement recognition of tax positions taken or expected to be taken on a tax return that are not certain to be realized. No liability has been recognized by the Organization for uncertain tax positions as of December 31, 2014 and 2013. The Organization's tax returns are subject to review and examination by federal and state authorities. The tax returns for the current year as well as fiscal years 2011 and thereafter are open to examination by federal and state authorities.

Revenue and Assessments

The Organization receives its revenues from NERC through a net energy-to-load allocation for all load-serving entities within its geographical area. The revenue allocation is prescribed under the Energy Policy Act of 2005 in the United States and similar arrangements in Saskatchewan and Manitoba. Any other revenues are collected on a fee-for-service basis at no cost, if applicable.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Subsequent Events

The Organization has evaluated subsequent events through April 2, 2015, which is the date that the financial statements were approved and available to be issued.

NOTE 2 - NERC TRANSACTIONS

The Organization has entered into a delegation agreement with the North American Electric Reliability Corporation ("NERC") to enforce the Reliability Standards as set by NERC within a designated region. In connection with the current delegation agreement, the Organization has the ability to propose Reliability Standards and Regional Variances. The Organization has the authority to enforce the Reliability Standards as set by NERC and approved by regulatory authorities within the geographic boundaries. The Organization is subject to oversight from NERC and applicable regulations in the United States, Manitoba, and Saskatchewan.

To ensure the delegated functions have reasonable funding, NERC is to fund the Organization with the monies necessary to carry out its activities as per the agreement. A formula is devised that equitably allocates charges among the end users within the boundaries served by the Organization, based on net energy for load or through such other formula as provided. The Organization provides NERC with a board approved annual operating budget on or before June 30 of each year. Budgeted revenues from NERC were $8,741,442 and $9,098,927 for the years ended December 31, 2014 and 2013, respectively, which agree with the amounts received.

NOTE 3 - LEASE COMMITMENTS

The Organization has an operating lease for office space in St Paul, Minnesota. Rent expense was $237,745 for the years ended December 31, 2014 and 2013, respectively.

Future expected minimum lease payments under the lease as of December 31, 2014 are as follows:

Years Ending December 31	
2015	$ 266,514
2016	274,537
2017	282,812
2018	291,277
2019	300,058
Thereafter	900,078
	$ 2,315,276

NOTE 4 - PROPERTY, IMPROVEMENTS AND EQUIPMENT

The following is a schedule of property, improvements and equipment as of December 31:

	2014	2013
Equipment	$ 1,795,454	$ 1,731,631
Furniture	429,772	422,802
Leasehold improvements	328,136	321,206
	2,553,362	2,475,639
Less: Accumulated depreciation	(1,675,671)	(1,281,070)
Net Property, Improvements and Equipment	$ 877,691	$ 1,194,569

NOTE 5 - LINE OF CREDIT

The Organization has a revolving line of credit from National Cooperative Service Corporation (NCSC) with an established credit limit of $2,000,000. The interest rate is equal to the NCSC Line of Credit Rate in effect from time to time, not to exceed the Prevailing Bank Prime Rate as published in the "Money Rates" column of the eastern edition of the *Wall Street Journal* on the publication day immediately preceding the day on which an adjustment in the interest rate becomes effective. The Organization is required to maintain a Debt Service Coverage Ratio of not less than 1.00. The line of credit is secured by substantially all assets of the Organization, and expires on February 26, 2017. There were no outstanding balances at December 31, 2014 or 2013, respectively.

NOTE 6 - RETIREMENT PLANS

Postretirement Health Plan

The Organization has a defined benefit postretirement health plan available to eligible current and future retirees. Information regarding the plan as of December 31 was as follows:

	2014	2013
Change in projected benefit obligation		
Benefit obligation at beginning of year	$ 882,395	$ 880,141
Service cost	161,535	169,757
Interest cost	44,340	36,195
Actuarial (gain) loss	163,942	(200,476)
Benefits paid	(4,564)	(3,222)
Benefit obligation at end of year	1,247,648	882,395
Change in plan assets		
Fair value of plan assets at beginning of year	729,224	532,807
Actual return on plan assets	7,851	59,097
Employer contribution	104,841	140,542
Benefits paid	(4,564)	(3,222)
Fair value of plan assets at end of year	837,352	729,224
Unfunded status recognized as a noncurrent liability	$ (410,296)	$ (153,171)
Weighted average assumptions used to calculate the benefit obligation-discount rate	4.01%	5.04%

Net periodic postretirement benefit expense for the years ending December 31 is comprised of the following:

	2014	2013
Components of net periodic benefit cost		
Service cost	$ 161,535	$ 169,757
Interest cost	44,340	36,195
Expected return on plan assets	(46,762)	(35,073)
Amortization of prior service credit	(38,601)	(38,601)
Amortization of actuarial loss	-	8,405
Net periodic benefit cost	$ 120,512	$ 140,683
Weighted-average assumptions used to calculate the net periodic benefit cost		
Discount rate	5.04%	4.12%
Expected return on plan assets	6.00%	6.00%
Rate of compensation increases	N/A	N/A

The expected rates of return on plan assets are based on the weighting of the Organization's asset allocations, the 30-year rolling historical average returns, and recent historical average return.

NOTE 6 - RETIREMENT PLANS (Continued)

Assumed health care cost trend rates used to determine the benefit obligation at December 31 consist of the following:

	2014	2013
Health care cost trend rate assumed for next year	9.3%	9.7%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2025	2025

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A one-percentage point change in assumed health care trend rates would have the following effects:

	One-Percentage Point	
	Increase	Decrease
Effect on total of service cost and interest cost	$ 57,867	$ (42,703)
Effect on postretirement benefit obligation	304,331	(230,340)

Plan related changes other than net periodic cost included in retirement benefit expense:

	2014	2013
Actuarial (gain) loss arising during the year	$ 202,853	$ (232,905)
Amortization of prior year service cost	38,601	38,601
	$ 241,454	$ (194,304)

The Organization employs a total return investment approach for plan assets with a mix of equity and debt investments used to maximize the long-term appreciation of plan assets for a prudent level of risk. The Organization's plan assets are invested in various funds, which consist of both stocks and bonds. The equity component includes investment in companies of various sizes, with an emphasis on large cap stocks, and represents several investment styles. The equity portion also includes an allocation to international stocks. Investments in bonds are diversified into three portfolios that invest mainly in U.S. treasuries, high quality corporate issues and mortgage securities.

Percentage of fair value by investment category at December 31, are as follows:

	2014	2013
Equity Securities	35%	36%
Debt Securities	44%	53%
Other	21%	11%

NOTE 6 - RETIREMENT PLANS (Continued)

The fair values of the Organization's postretirement health plan assets at December 31, by asset category, are as follows:

	2014 Quoted Prices in Active Markets for Identical Assets (Level 1)	2013 Quoted Prices in Active Markets for Identical Assets (Level 1)
Asset category		
Cash equivalents	$ 8,906	$ 7,490
Mutual funds-bonds	372,528	383,724
Mutual funds-equities	290,396	265,854
Mutual funds-balanced	165,522	72,156
	$ 837,352	$ 729,224

Cash equivalents - Investments in cash equivalents consist of money market funds and are classified as Level 1 as they are traded in an active market for which closing prices are readily available.

Mutual Funds - Investments in mutual funds are classified as Level 1 as they are traded in an active market for which closing prices are readily available.

There have been no changes in the fair market valuation techniques and inputs as of December 31, 2014 and 2013.

While the plan believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date.

Estimated future benefit payments (which reflect expected future service, as appropriate) as of December 31, 2014 are as follows:

Years Ending December 31	
2015	$ 5,530
2016	6,637
2017	11,083
2018	20,405
2019	33,685
2020 - 2024	317,779

It is reasonably possible that changes in these estimates could occur in the near term and that actual results could differ from these estimates and could have a material effect on the financial statements.

The Organization expects to contribute $100,967 to the plan in 2015.

NOTE 6 - RETIREMENT PLANS (Continued)

Defined Contribution Pension Plan

The Organization has a thrift savings plan to replace the terminated multiple-employer plan for the benefit of its employees. The Organization's previous 401(k) plan was converted into the new plan as well as the establishment of a new, non-elective employer contribution plan. In order to participate in the plan, employees must have attained age 20 and have completed one month of service. Employees may contribute up to the IRS limitations for their elective deferral, with a 50% matching contribution from the Organization. For employees to receive the non-elective or employer contribution, they must have worked 1,000 hours during the plan year. The Organization matched $255,776 and $241,044 of employee deferrals as of December 31, 2014 and 2013, respectively. In addition, the Organization elected to make an employer contribution in the amount of $430,111 and $370,263 for the years ended December 31, 2014 and 2013, respectively.

The Organization also has a 457B plan. Eligible employees may contribute an elective deferral, with a discretionary matching contribution from the Organization. Employee contributions were $20,875 and $16,226, for the years ended December 31, 2014 and 2013, respectively. The Organization matched $10,438 and $6,675, of employee deferrals for the years ended December 31, 2014 and 2013, respectively.

The Organization also has a 457F plan. Employer contribution amounts for employees in excess of IRS contribution limits are deposited to the 457F. The Organization contributed in the amounts of $23,117 and $20,950, for the years ended December 31, 2014 and 2013, respectively.

ATTACHMENT 4

2014 ACTUAL COST-TO-BUDGET COMPARISON

AND

2014 AUDITED FINANCIAL REPORT

FOR

NORTHEAST POWER COORDINATING COUNCIL, INC.

Via Email

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS. NEW YORK. NY 10018 (212) 840-1070 FAX (212) 302-2782

April 28, 2015

North American Electric Reliability Corporation
3343 Peachtree Road, NE
Fourth Floor East Tower – Suite 400
Atlanta, Georgia 30326
Attention: Mr. Michael Walker

Subject: NPCC 2014 True Up Actual vs. Budget Variance Analysis
True Up Filing Based on Audited 2014 Financial Statements

Dear Michael:

Enclosed is the Northeast Power Coordinating Council, Inc. (NPCC) submittal regarding the 2014 NPCC actual vs. budget variances. NPCC's independent audit performed by Pricewaterhouse Coopers LLP was concluded on March 27, 2015 and forwarded to NERC for its information and provision to FERC.

As you know, NPCC is a Cross-border Regional Entity which provides Regional Entity functions and services through its regional entity (RE) division. The establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria are provided through the criteria services (CS) division of NPCC. The CS division is funded by assessments to the Independent System Operators/Balancing Authority Areas within the Region based on their respective Net Energy for Load.

No Regional Entity division assessments were used to fund CS division activities. Allocation between the RE division and CS division represents a 95/5 split for 2014 based upon total corporate FTEs of 36.86 in the RE division and 2.14 in the CS division. No indirect costs were allocated from the CS division to the RE division and no cross subsidies exist. In addition, NPCC does not budget for interest income and reports such income apportioned based upon its Regional Entity (RE) and Criteria Services (CS) division full time equivalent (FTE) ratio.

Actual total expenses for NPCC's RE division for 2014 were $13,777,528 (excluding non-operating expenses which represent change in pension liability on a termination basis vs. liability for the plan on an ongoing basis consistent with actuarial review and a Board of Directors approved additional contribution to the pension plan associated with plan termination initiated due to cross-testing IRS rules) which is $493,479 or 3.5% under the 2014 operating budget of $14,271,007. Actual total expenses for NPCC's CS division for 2014 were $1,084,317 (excluding non-operating expenses) which is $4,783 or 0.4% under the 2014 operating budget of $1,089,100. In the aggregate, actual total expenses (excluding non-operating expenses) for the NPCC RE and CS divisions were $14,861,847 which is $498,260 or 3.2% under the 2014 total corporate budget of $15,360,107. Indirect expenses are allocated to the direct programs based on FTE ratio. As approved by its Board of Directors, NPCC used reserves in the amount of $2,500,000 in order to increase the funded level of the pension plan closer to projected liabilities based upon 2014 mortality tables and segmented interest rate assumptions. NPCC filed the IRS required documentation in December, 2014 to facilitate pension plan termination. Operating cash reserves were not used to fund any other activities or services in 2014.

Variances from budget in total for NPCC, total non-statutory, total statutory and total by statutory program area are provided on a line-item basis using the template provided by NERC which presents actual and budgeted costs on program-by-program format. A single consolidated budget versus actual cost comparison is presented for Administrative Services in order to be consistent with the presentation in NPCC's 2014 Business Plan and Budget. Explanations of significant expense variances are provided for the Regional Entity division in total and by program area where the explanation differs from that for the Regional Entity total.

Should you have any questions please do not hesitate to contact me via email at jhala@npcc.org or via telephone at (212) 840-1070.

Sincerely,

Jessica Hala

Jessica Hala
Manager, Finance and Accounting

JH: jh
Enclosures

cc: Mr. Edward A. Schwerdt – NPCC President & CEO
Ms. Jennifer Budd Mattiello – NPCC Vice President & COO

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary
Total NPCC (RE and CS Divisions)

	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)
Funding			
ERO Funding			
Assessments	13,611,880	13,611,881	-
Penalty Sanctions	153,000	153,000	-
Total ERO Funding	**13,764,880**	**13,764,881**	**-**
Federal Grants	-	-	-
Non-Statutory Assessments	989,708	989,708	-
Testing	-	-	-
Services & Software	-	-	-
Workshop Fees	62,579	64,000	(1,421)
Interest	12,291	-	12,291
Miscellaneous	5,245	-	5,245
Total Funding (A)	**14,834,703**	**14,818,589**	**16,115**
Expenses			
Personnel Expenses			
Salaries	6,144,364	6,223,393	(79,029)
Payroll Taxes	407,020	405,848	1,172
Employee Benefits	1,205,396	1,494,415	(289,019)
Savings & Retirement	1,203,166	1,254,179	(51,013)
Total Personnel Expenses	**8,959,946**	**9,377,836**	**(417,890)**
Meeting Expenses			
Meetings	285,176	375,000	(89,824)
Travel	757,752	953,000	(195,248)
Conference Calls	32,720	77,000	(44,280)
Total Meeting Expenses	**1,075,648**	**1,405,000**	**(329,352)**
Operating Expenses			
Consultants & Contracts	2,230,942	1,979,433	251,509
Rent & Improvements	744,102	737,272	6,830
Office Costs	548,279	536,500	11,779
Professional Services	939,353	966,500	(27,147)
Miscellaneous	41,592	83,567	(41,975)
Depreciation	321,986	274,000	47,986
Total Operating Expenses	**4,826,254**	**4,577,272**	**248,982**
Indirect Expenses	**-**	**-**	**-**
Other Non-Operating Expenses	**1,383,663**	**-**	**1,383,664**
Total Expenses (B)	**16,245,511**	**15,360,108**	**885,404**
Change in Assets (A - B)	**(1,410,808)**	**(541,519)**	**(869,289)**
Fixed Assets			
Depreciation	(321,986)	(274,000)	(47,986)
Computer & Software CapEx	31,171	108,000	(76,829)
Furniture & Fixtures CapEx	-	-	-
Equipment CapEx	(70,131)	-	(70,131)
Leasehold Improvements	3,657	-	3,657
Incr(Dec) in Fixed Assets	**(357,289)**	**(166,000)**	**(191,289)**
Allocation of Fixed Assets	-	-	-
Total Inc(Dec) in Fixed Assets (C)	**(357,289)**	**(166,001)**	**(191,288)**
TOTAL BUDGET (B + C)	**15,888,222**	**15,194,107**	**694,116**
Change in Working Capital (A-B-C)	**(1,053,519)**	**(375,518)**	**(678,001)**
FTE's	**38.42**	**39.00**	**(0.58)**

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

TOTAL STATUTORY	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	13,611,880	13,611,881	-	0.00%
Penalty Sanctions	153,000	153,000	-	0.00%
Total ERO Funding	13,764,880	13,764,881	-	0.00%
Federal Grants	-	-	-	
Non-Statutory Assessments	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	62,579	64,000	(1,421)	-2.22%
Interest	11,616	-	11,616	
Miscellaneous	5,245	-	5,245	
Total Funding (A)	13,844,320	13,828,881	15,440	0.11%
Expenses				
Personnel Expenses				
Salaries	5,785,898	5,911,227	(125,329)	-2.12%
Payroll Taxes	383,221	384,312	(1,091)	-0.28%
Employee Benefits	1,106,658	1,430,262	(323,604)	-22.63%
Savings & Retirement	1,071,843	1,124,361	(52,518)	-4.67%
Total Personnel Expenses	8,347,620	8,850,162	(502,542)	-5.68%
Meeting Expenses				
Meetings	284,156	365,000	(80,844)	-22.15%
Travel	713,452	890,000	(176,548)	-19.84%
Conference Calls	32,720	77,000	(44,280)	-57.51%
Total Meeting Expenses	1,030,328	1,332,000	(301,672)	-22.65%
Operating Expenses				
Consultants & Contracts	2,220,677	1,924,433	296,244	15.39%
Rent & Improvements	744,102	737,272	6,830	0.93%
Office Costs	547,325	536,500	10,825	2.02%
Professional Services	939,353	966,500	(27,147)	-2.81%
Miscellaneous	41,141	80,000	(38,859)	-48.57%
Depreciation	306,844	250,000	56,844	22.74%
Total Operating Expenses	4,799,442	4,494,705	304,737	6.78%
Indirect Expenses	(399,862)	(405,860)	5,998	-1.48%
Other Non-Operating Expenses	1,167,994	-	1,167,995	
Total Expenses (B)	14,945,522	14,271,007	674,516	4.73%
Change in Assets (A - B)	(1,101,202)	(442,127)	(659,076)	149.07%
Fixed Assets				
Depreciation	(306,844)	(250,000)	(56,844)	22.74%
Computer & Software CapEx	31,171	108,000	(76,829)	-71.14%
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	(70,131)	-	(70,131)	
Leasehold Improvements	3,657	-	3,657	
Incr(Dec) in Fixed Assets	(342,147)	(142,000)	(200,147)	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	(342,147)	(142,001)	(200,146)	140.95%
TOTAL BUDGET (B + C)	**14,603,375**	**14,129,006**	**474,370**	**3.36%**
Change in Working Capital (A-B-C)	**(759,055)**	**(300,126)**	**(458,930)**	152.91%
FTE's	**36.28**	**36.86**	**(0.58)**	**-1.57%**

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

NON-STATUTORY	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	-	-	-	
Penalty Sanctions	-	-	-	
Total ERO Funding	-	-	-	
Federal Grants	-	-	-	
Non-Statutory Assessments	989,708	989,708	-	0.00%
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	675	-	675	
Miscellaneous	-	-	-	
Total Funding (A)	990,383	989,708	675	0.07%
Expenses				
Personnel Expenses				
Salaries	358,466	312,166	46,300	14.83%
Payroll Taxes	23,799	21,536	2,263	10.51%
Employee Benefits	98,738	64,153	34,585	53.91%
Savings & Retirement	131,323	129,818	1,505	1.16%
Total Personnel Expenses	612,326	527,674	84,652	16.04%
Meeting Expenses				
Meetings	1,020	10,000	(8,980)	-89.80%
Travel	44,300	63,000	(18,700)	-29.68%
Conference Calls	-	-	-	
Total Meeting Expenses	45,320	73,000	(27,680)	-37.92%
Operating Expenses				
Consultants & Contracts	10,265	55,000	(44,735)	-81.34%
Rent & Improvements	-	-	-	
Office Costs	954	-	954	
Professional Services	-	-	-	
Miscellaneous	451	3,567	(3,116)	-87.36%
Depreciation	15,142	24,000	(8,858)	-36.91%
Total Operating Expenses	26,812	82,567	(55,755)	-67.53%
Indirect Expenses	399,859	405,859	(6,000)	-1.48%
Other Non-Operating Expenses	215,669	-	215,669	
Total Expenses (B)	1,299,986	1,089,100	210,886	19.36%
Change in Assets (A - B)	(309,603)	(99,392)	(210,211)	211.50%
Fixed Assets				
Depreciation	(15,142)	(24,000)	8,858	-36.91%
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	(15,142)	(24,000)	8,858	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	(15,142)	(24,000)	8,858	-36.91%
TOTAL BUDGET (B + C)	**1,284,844**	**1,065,100**	**219,744**	**20.63%**
Change in Working Capital (A-B-C)	**(294,461)**	**(75,392)**	**(219,069)**	290.57%
FTE's	**2.14**	**2.14**	**-**	**0.00%**

TOTAL NPCC

Personnel Expenses

In 2014 NPCC experienced several partial year vacancies but ended the year fully staffed. These vacancies resulted in lower salary and associated incentive compensation. Despite not being at a full staff complement at times during the year, NPCC performed all of its 2014 delegated responsibilities as well as its goals and objectives, including:

- Conducted 33 off-site Operations & Planning (O&P) audits, five on-site O&P audits, 31 off-site CIP audits, seven on-site CIP audits and 473 individual spot checks were performed involving 35 registered entities;
- Processed 201 Technical Feasibility Exception (TFE) submittals from 19 registered entities: 123 new TFEs, 59 Material Change Reports(MCRs) and 19 Terminations for TFEs;
- Closed 140 violations;
- Accepted mitigation plans for 72 violations;
- Examined 85 events of which five were category two or higher;
- Processed 20 new entity registrations, 18 deactivations, 8 entity name changes and three certification reviews.

In the benefits area, NPCC was able to trim insurance renewal expenses resulting in significant cost savings. Additionally, a substantial number of professionals continue to waive health insurance coverage opting for superior coverage from a prior employer or spousal insurance coverages.

WECC CEA Revenue and Expenses

WECC CEA related expenses and offsetting revenue of $5,245 were related to the O&P and CIP audits conducted during 2012. The total actual expenses related to the WECC audits were trued up with WECC in 2014, as per the CEA Agreement.

Meeting Expenses

Continued efforts to limit the number of attendees sent to off-site meetings, and to hold more meetings onsite or via webinar where effective, have kept meeting, travel and conference call expenses under budget. Conference calls underage was also based on lower negotiated rates with a new provider and credit negotiated for service interruption.

Consultants and Contracts

Overage is primarily due to additional use of consultants in the Reliability Assessment and Performance Analysis (RAPA) program area related to implementation of the revised BES definition and providing BESnet support to NERC; added use of contractors in the Compliance program during periods of staff vacancy; and additional efforts related to system frequency response and generator governor response and the implementation of the NPCC program for the Simultaneous Activation of Reserve (SAR) in the Situation Awareness and Infrastructure Security program.

Miscellaneous

Under budget due to ongoing cost cutting efforts in all areas.

Depreciation

Over budget due to additional assets placed in service related to CMEP Data Administration Application (CDAA) software development to enhance the efficiencies of compliance activities for both registered entities and Regional Entity staffs.

Non-Operating Expenses

Changes in NPCC's pension liability based on actuarial report are reflected in the non-operating expense line.

Fixed Assets

Computer & Software capital expenditures were under budget due to a portion of costs related to CMEP Data Administration Application (CDAA) software being expensed rather than capitalized based on GAAP. Equipment capital expenditure represents the write off of old equipment during 2014.

Compliance Hearings

No funds were budgeted in association with NPCC conducting compliance hearings and no hearings have been initiated to date in NPCC.

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

RELIABILITY STANDARDS	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	1,431,239	1,431,239	-	0.00%
Penalty Sanctions	16,091	16,091		0.00%
Total ERO Funding	1,447,330	1,447,330	-	0.00%
Federal Grants	-	-	-	
Non-Statutory Assessments	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	1,447,330	1,447,330	-	0.00%
Expenses				
Personnel Expenses				
Salaries	468,322	502,840	(34,518)	-6.86%
Payroll Taxes	34,110	31,305	2,805	8.96%
Employee Benefits	86,708	131,342	(44,634)	-33.98%
Savings & Retirement	80,829	87,449	(6,620)	-7.57%
Total Personnel Expenses	669,969	752,936	(82,967)	-11.02%
Meeting Expenses				
Meetings	6,986	25,000	(18,014)	-72.06%
Travel	107,950	110,000	(2,050)	-1.86%
Conference Calls	-	-	-	
Total Meeting Expenses	114,936	135,000	(20,064)	-14.86%
Operating Expenses				
Consultants & Contracts	7,235	30,000	(22,765)	-75.88%
Rent & Improvements	-	-	-	
Office Costs	1,403	-	1,403	
Professional Services	-	-	-	
Miscellaneous	38	-	38	
Depreciation	-	-	-	
Total Operating Expenses	8,676	30,000	(21,324)	-71.08%
Indirect Expenses	546,443	555,686	(9,243)	-1.66%
Other Non-Operating Expenses	90,757	-	90,757	
Total Expenses (B)	1,430,781	1,473,622	(42,841)	-2.91%
Change in Assets (A - B)	16,549	(26,292)	42,841	-162.94%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	(39,261)	(26,292)	(12,969)	49.33%
Total Inc(Dec) in Fixed Assets (C)	(39,261)	(26,292)	(12,969)	49.33%
TOTAL BUDGET (B + C)	**1,391,520**	**1,447,330**	**(55,810)**	**-3.86%**
Change in Working Capital (A-B-C)	**55,810**	**-**	**55,810**	
FTE's	**2.93**	**2.93**	**-**	**0.00%**

RELIABILITY STANDARDS

Consultants and Contracts

Under budget as a result of judicious use of contractor and consultant services to complement staff functions.

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

WECC CEA Responsibilities	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)
Funding			
ERO Funding			
Assessments	-	-	-
Penalty Sanctions	-	-	
Total ERO Funding	-	-	-
Federal Grants	-	-	-
Non-Statutory Assessments	-	-	-
Testing	-	-	-
Services & Software	-	-	-
Workshop Fees	-	-	-
Interest	-	-	-
Miscellaneous	5,245	-	5,245
Total Funding (A)	5,245	-	5,245
Expenses			
Personnel Expenses			
Salaries	5,245	-	5,245
Payroll Taxes	-	-	-
Employee Benefits	-	-	-
Savings & Retirement	-	-	-
Total Personnel Expenses	5,245	-	5,245
Meeting Expenses			
Meetings	-	-	-
Travel	-	-	-
Conference Calls	-	-	-
Total Meeting Expenses	-	-	-
Operating Expenses			
Consultants & Contracts	-	-	-
Rent & Improvements	-	-	-
Office Costs	-	-	-
Professional Services	-	-	-
Miscellaneous	-	-	-
Depreciation	-	-	-
Total Operating Expenses	-	-	-
Indirect Expenses	-	-	-
Other Non-Operating Expenses	-	-	-
Total Expenses (B)	5,245	-	5,245
Change in Assets (A - B)	-	-	-
Fixed Assets			
Depreciation	-	-	-
Computer & Software CapEx	-	-	-
Furniture & Fixtures CapEx	-	-	-
Equipment CapEx	-	-	-
Leasehold Improvements	-	-	-
Incr(Dec) in Fixed Assets	-	-	-
Allocation of Fixed Assets	-	-	-
Total Inc(Dec) in Fixed Assets (C)	-	-	-
TOTAL BUDGET (B + C)	**5,245**	**-**	**5,245**
Change in Working Capital (A-B-C)	**-**	**-**	**-**
FTE's	**-**	**-**	**-**

WECC CEA Revenue and Expenses

WECC CEA related expenses and offsetting revenue of $5,245 were related to the O&P and CIP audits conducted during 2012. The total actual expenses related to the WECC audits were trued up with WECC in 2014, as per the CEA Agreement.

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

COMPLIANCE OPERATIONS, ENFORCEMENT and ORGANIZATION REGISTRATION	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	7,991,503	7,991,503	-	0.00%
Penalty Sanctions	87,868	87,868	-	0.00%
Total ERO Funding	8,079,371	8,079,371	-	0.00%
Federal Grants	-	-	-	
Non-Statutory Assessments	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	8,079,371	8,079,371	-	0.00%
Expenses				
Personnel Expenses				
Salaries	2,152,462	2,287,504	(135,042)	-5.90%
Payroll Taxes	147,589	162,571	(14,982)	-9.22%
Employee Benefits	422,474	537,087	(114,613)	-21.34%
Savings & Retirement	245,847	298,890	(53,043)	-17.75%
Total Personnel Expenses	2,968,372	3,286,052	(317,680)	-9.67%
Meeting Expenses				
Meetings	12,054	25,000	(12,946)	-51.78%
Travel	312,710	375,000	(62,290)	-16.61%
Conference Calls	-	-	-	
Total Meeting Expenses	324,764	400,000	(75,236)	-18.81%
Operating Expenses				
Consultants & Contracts	1,541,340	1,394,433	146,907	10.54%
Rent & Improvements	-	-	-	
Office Costs	26,335	-	26,335	
Professional Services	-	-	-	
Miscellaneous	578	-	578	
Depreciation	-	-	-	
Total Operating Expenses	1,568,253	1,394,433	173,820	12.47%
Indirect Expenses	2,889,612	3,034,462	(144,850)	-4.77%
Other Non-Operating Expenses	105,481	-	105,481	
Total Expenses (B)	7,856,482	8,114,947	(258,465)	-3.19%
Change in Assets (A - B)	222,889	(35,576)	258,465	-726.52%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	31,171	108,000	(76,829)	-71.14%
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	31,171	108,000	(76,829)	
Allocation of Fixed Assets	(214,397)	(143,576)	(70,821)	49.33%
Total Inc(Dec) in Fixed Assets (C)	(183,226)	(35,576)	(147,650)	415.03%
TOTAL BUDGET (B + C)	**7,673,256**	**8,079,371**	**(406,115)**	**-5.03%**
Change in Working Capital (A-B-C)	**406,115**	**-**	**406,115**	
FTE's	**15.67**	**16.00**	**(0.33)**	**-2.06%**

COMPLIANCE OPERATIONS, ENFORCEMENT and ORGANIZATION REGISTRATION

Personnel
Under budget due to temporary vacancies during the year and at risk compensation component based on corporate goal attainment and individual performance. Fully staffed at year end.

Consultants and Contracts
Overage is primarily due to additional use of contractors during periods of staff vacancy.

Office Costs
Over budget due to costs related to CMEP Data Administration Application (CDAA) software ongoing maintenance being expensed rather than capitalized based on GAAP.

Fixed Assets
Computer & Software capital expenditures were under budget due to a portion of costs related to CMEP Data Administration Application (CDAA) software being expensed rather than capitalized based on GAAP.

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	2,910,322	2,910,322	-	0.00%
Penalty Sanctions	32,017	32,017		0.00%
Total ERO Funding	2,942,339	2,942,339	-	0.00%
Federal Grants	-	-	-	
Non-Statutory Assessments	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	2,942,339	2,942,339	-	0.00%
Expenses				
Personnel Expenses				
Salaries	878,385	904,028	(25,643)	-2.84%
Payroll Taxes	57,767	60,329	(2,562)	-4.25%
Employee Benefits	185,396	226,225	(40,829)	-18.05%
Savings & Retirement	157,235	190,390	(33,155)	-17.41%
Total Personnel Expenses	1,278,783	1,380,972	(102,189)	-7.40%
Meeting Expenses				
Meetings	41,142	45,000	(3,858)	-8.57%
Travel	129,401	175,000	(45,599)	-26.06%
Conference Calls	-	-	-	
Total Meeting Expenses	170,543	220,000	(49,457)	-22.48%
Operating Expenses				
Consultants & Contracts	434,436	275,000	159,436	57.98%
Rent & Improvements	-	-	-	
Office Costs	15,261	13,000	2,261	17.39%
Professional Services	-	-	-	
Miscellaneous	862	-	862	
Depreciation	-	-	-	
Total Operating Expenses	450,559	288,000	162,559	56.44%
Indirect Expenses	1,087,109	1,105,682	(18,573)	-1.68%
Other Non-Operating Expenses	241,185	-	241,185	
Total Expenses (B)	3,228,179	2,994,654	233,525	7.80%
Change in Assets (A - B)	(285,840)	(52,315)	(233,525)	446.38%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	(78,121)	(52,315)	(25,806)	49.33%
Total Inc(Dec) in Fixed Assets (C)	(78,121)	(52,315)	(25,806)	49.33%
TOTAL BUDGET (B + C)	**3,150,058**	**2,942,339**	**207,719**	**7.06%**
Change in Working Capital (A-B-C)	**(207,719)**	**-**	**(207,719)**	
FTE's	**5.58**	**5.83**	**(0.25)**	**-4.29%**

RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS

Personnel

Under budget due to temporary vacancies during the year and at risk compensation component based on corporate goal attainment and individual performance. Fully staffed at year end.

Consultants and Contracts

Overage is primarily due to additional use of consultants in the Reliability Assessment and Performance Analysis (RAPA) program area related to implementation of the revised BES definition and providing BESnet support to NERC.

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

TRAINING, EDUCATION and OPERATOR CERTIFICATION	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	131,306	131,306	-	0.00%
Penalty Sanctions	549	549		0.00%
Total ERO Funding	131,855	131,855	-	0.00%
Federal Grants	-	-	-	
Non-Statutory Assessments	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	62,579	64,000	(1,421)	-2.22%
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	194,434	195,855	(1,421)	-0.73%
Expenses				
Personnel Expenses				
Salaries	17,285	17,448	(163)	-0.93%
Payroll Taxes	1,162	1,063	99	9.31%
Employee Benefits	3,776	4,500	(724)	-16.09%
Savings & Retirement	4,424	4,776	(352)	-7.37%
Total Personnel Expenses	26,647	27,787	(1,140)	-4.10%
Meeting Expenses				
Meetings	147,920	135,000	12,920	9.57%
Travel	2,144	15,000	(12,856)	-85.71%
Conference Calls	-	-	-	
Total Meeting Expenses	150,064	150,000	64	0.04%
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	2,382	-	2,382	
Professional Services	-	-	-	
Miscellaneous	1,674	-	1,674	
Depreciation	-	-	-	
Total Operating Expenses	4,056	-	4,056	
Indirect Expenses	18,426	18,965	(539)	-2.84%
Other Non-Operating Expenses	8,191	-	8,191	
Total Expenses (B)	207,384	196,752	10,632	5.40%
Change in Assets (A - B)	(12,950)	(897)	(12,053)	1343.70%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	(1,340)	(897)	(443)	49.38%
Total Inc(Dec) in Fixed Assets (C)	(1,340)	(897)	(443)	49.38%
TOTAL BUDGET (B + C)	**206,044**	**195,855**	**10,189**	**5.20%**
Change in Working Capital (A-B-C)	**(11,610)**	**-**	**(11,610)**	
FTE's	**0.10**	**0.10**	**-**	**0.00%**

TRAINING, EDUCATION and OPERATOR CERTIFICATION

Meeting expenses

More meetings held on-site resulted in over budget meeting expenses offset by under budget travel expenses.

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

SITUATION AWARENESS and INFRASTRUCTURE SECURITY	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	1,447,636	1,447,636	-	0.00%
Penalty Sanctions	16,475	16,475		0.00%
Total ERO Funding	1,464,111	1,464,111	-	0.00%
Federal Grants	-	-	-	
Non-Statutory Assessments	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	1,464,111	1,464,111	-	0.00%
Expenses				
Personnel Expenses				
Salaries	494,704	522,672	(27,968)	-5.35%
Payroll Taxes	34,781	32,961	1,820	5.52%
Employee Benefits	57,977	88,851	(30,874)	-34.75%
Savings & Retirement	108,308	117,586	(9,278)	-7.89%
Total Personnel Expenses	695,770	762,070	(66,300)	-8.70%
Meeting Expenses				
Meetings	5,438	25,000	(19,562)	-78.25%
Travel	57,495	60,000	(2,505)	-4.18%
Conference Calls	-	-	-	
Total Meeting Expenses	62,933	85,000	(22,067)	-25.96%
Operating Expenses				
Consultants & Contracts	170,076	75,000	95,076	126.77%
Rent & Improvements	-	-	-	
Office Costs	6,879	-	6,879	
Professional Services	-	-	-	
Miscellaneous	45	-	45	
Depreciation	-	-	-	
Total Operating Expenses	177,000	75,000	102,000	136.00%
Indirect Expenses	559,369	568,962	(9,593)	-1.69%
Other Non-Operating Expenses	165,096	-	165,096	
Total Expenses (B)	1,660,168	1,491,032	169,136	11.34%
Change in Assets (A - B)	(196,057)	(26,921)	(169,136)	628.27%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	(40,199)	(26,921)	(13,278)	49.32%
Total Inc(Dec) in Fixed Assets (C)	(40,199)	(26,921)	(13,278)	49.32%
TOTAL BUDGET (B + C)	**1,619,969**	**1,464,111**	**155,858**	**10.65%**
Change in Working Capital (A-B-C)	**(155,858)**	**-**	**(155,858)**	
FTE's	**3.00**	**3.00**	**-**	**0.00%**

SITUATION AWARENESS and INFRASTRUCTURE SECURITY

Consultants and Contracts

Over budget due to additional programs and efforts related to system frequency response and generator governor response and the implementation of the NPCC program for the Simultaneous Activation of Reserve (SAR).

Northeast Power Coordinating Council, Inc.
2014 Statement of Activities Summary

ADMINISTRATIVE SERVICES	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	(300,126)	(300,126)	-	0.00%
Penalty Sanctions	-	-		
Total ERO Funding	(300,126)	(300,126)	-	0.00%
Federal Grants	-	-	-	
Non-Statutory Assessments	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	11,616	-	11,616	
Miscellaneous	-	-	-	
Total Funding (A)	(288,510)	(300,126)	11,616	-3.87%
Expenses				
Personnel Expenses				
Salaries	1,769,495	1,676,735	92,760	5.53%
Payroll Taxes	107,812	96,083	11,729	12.21%
Employee Benefits	350,327	442,257	(91,930)	-20.79%
Savings & Retirement	475,200	425,270	49,930	11.74%
Total Personnel Expenses	2,702,834	2,640,345	62,489	2.37%
Meeting Expenses				
Meetings	70,616	110,000	(39,384)	-35.80%
Travel	103,752	155,000	(51,248)	-33.06%
Conference Calls	32,720	77,000	(44,280)	-57.51%
Total Meeting Expenses	207,088	342,000	(134,912)	-39.45%
Operating Expenses				
Consultants & Contracts	67,590	150,000	(82,410)	-54.94%
Rent & Improvements	744,102	737,272	6,830	0.93%
Office Costs	495,065	523,500	(28,435)	-5.43%
Professional Services	939,353	966,500	(27,147)	-2.81%
Miscellaneous	37,944	80,000	(42,056)	-52.57%
Depreciation	306,844	250,000	56,844	22.74%
Total Operating Expenses	2,590,898	2,707,272	(116,374)	-4.30%
Indirect Expenses	(5,500,820)	(5,689,617)	188,797	-3.32%
Other Non-Operating Expenses	557,284	-	557,284	
Total Expenses (B)	557,284	-	557,284	
Change in Assets (A - B)	(845,794)	(300,126)	(545,668)	181.81%
Fixed Assets				
Depreciation	(306,844)	(250,000)	(56,844)	22.74%
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	(70,131)	-	(70,131)	
Leasehold Improvements	3,657	-	3,657	
Incr(Dec) in Fixed Assets	(373,318)	(250,000)	(123,318)	
Allocation of Fixed Assets	373,318	250,000	123,318	49.33%
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	**557,284**	**-**	**557,284**	
Change in Working Capital (A-B-C)	**(845,794)**	**(300,126)**	**(545,668)**	181.81%
FTE's	**9.00**	**9.00**	**-**	**0.00%**

ADMINISTRATIVE SERVICES

Interest Income
Interest income, while not budgeted, was allocated by FTE ratio between statutory and non-statutory.

Consultants and Contracts
Under budget as a result of judicious use of contractor and consultant services to complement staff functions.

Miscellaneous
Under budget due to ongoing cost cutting efforts in all areas.

Depreciation
Over budget due to additional assets placed in service related to CMEP Data Administration Application (CDAA) software development to enhance the efficiencies of compliance activities for both registered entities and Regional Entity staffs.

Fixed Assets
Computer & Software capital expenditures were under budget due to a portion of costs related to CMEP Data Administration Application (CDAA) software being expensed rather than capitalized based on GAAP. Equipment capital expenditure represents the write off of old equipment during 2014.

NPCC
Penalty Sanctions

Date Invoiced	Date Received	Entity Name	Amount	Year to Recognize for Business Plan & Budget					
				2011	2012	2013	2014	2015	2016
12/14/2009	12/17/2009		$ 10,000.00	$ 10,000.00					
12/14/2009	12/17/2009		10,000.00	10,000.00					
12/14/2009	12/17/2009		10,000.00	10,000.00					
12/14/2009	12/17/2009		10,000.00	10,000.00					
3/8/2010	3/19/2010		250,000.00	250,000.00					
4/12/2010	4/20/2010		5,000.00	5,000.00					
6/1/2010	6/9/2010		13,500.00	13,500.00					
8/9/2010	8/26/2010		40,000.00		40,000.00				
11/1/2010	11/30/2010		5,000.00		5,000.00				
12/9/2010	12/21/2010		450,000.00		450,000.00				
12/9/2010	12/21/2010		7,500.00		7,500.00				
		Subtotal - 2010	$ 811,000.00						
3/28/2011	4/7/2011		$ 30,000.00		30,000.00				
3/28/2011	4/12/2011		10,000.00		10,000.00				
4/7/2011	4/21/2011		2,500.00		2,500.00				
4/7/2011	4/15/2011		5,000.00		5,000.00				
4/7/2011	4/18/2011		7,500.00		7,500.00				
5/17/2011	5/26/2011		2,500.00		2,500.00				
5/17/2011	5/31/2011		35,000.00		35,000.00				
6/14/2011	6/20/2011		4,000.00		4,000.00				
6/2/2011	6/10/2011		2,500.00		2,500.00				
6/2/2011	6/13/2011		2,500.00		2,500.00				
6/2/2011	6/30/2011		7,500.00		7,500.00				
6/2/2011	6/30/2011		2,500.00		2,500.00				
6/27/2011	7/13/2011		15,000.00			15,000.00			
7/27/2011	8/10/2011		3,500.00			3,500.00			
7/27/2011	8/10/2011		5,000.00			5,000.00			
7/27/2011	8/10/2011		5,000.00			5,000.00			
7/27/2011	9/6/2011		15,000.00			15,000.00			
8/18/2011	9/13/2011		80,000.00			80,000.00			
9/6/2011	9/23/2011		2,500.00			2,500.00			
9/9/2011	9/19/2011		5,000.00			5,000.00			
9/6/2011	9/23/2011		50,000.00			50,000.00			
9/14/2011	9/26/2011		4,000.00			4,000.00			
9/9/2011	9/30/2011		7,500.00			7,500.00			
9/6/2011	10/3/2011		5,000.00			5,000.00			
10/4/2011	10/12/2011		6,000.00			6,000.00			
10/4/2011	10/14/2011		3,500.00			3,500.00			
10/4/2011	10/17/2011		5,000.00			5,000.00			
		Subtotal - 2011	$ 323,500.00						
2/22/2012	3/8/2012		$ 15,000.00			15,000.00			
2/22/2012	3/8/2012		5,000.00			5,000.00			
2/23/2012	3/12/2012		17,500.00			17,500.00			
2/22/2012	3/21/2012		25,000.00			25,000.00			
4/3/2012	5/1/2012		5,000.00			5,000.00			
4/2/2012	5/1/2012		3,800.00			3,800.00			
4/3/2012	5/2/2012		4,000.00			4,000.00			
5/10/2012	6/5/2012		10,000.00			10,000.00			
6/22/2012	7/3/2012		8,000.00				8,000.00		
6/22/2012	7/18/2012		25,000.00				25,000.00		
9/5/2012	10/2/2012		15,000.00				15,000.00		
12/4/2012	1/3/2013		30,000.00				30,000.00		
12/18/2012	1/10/2013		40,000.00				40,000.00		
		Subtotal - 2012	$ 203,300.00						
4/30/2013	5/30/2013		6,000.00				6,000.00		
4/30/2013	5/30/2013		5,000.00				5,000.00		
4/30/2013	5/30/2013		6,000.00				6,000.00		
4/30/2013	5/30/2013		6,000.00				6,000.00		
4/30/2013	5/30/2013		6,000.00				6,000.00		
4/30/2013	5/30/2013		6,000.00				6,000.00		
6/6/2013	7/5/2013		50,000.00					50,000.00	
6/6/2013	7/5/2013		10,000.00					10,000.00	
6/6/2013	7/5/2013		30,000.00					30,000.00	
6/6/2013	7/5/2013		25,000.00					25,000.00	
8/5/2013	9/4/2013		7,000.00					7,000.00	
10/3/2013	10/16/2013		25,000.00					25,000.00	
10/31/2013	11/1/2013		5,000.00					5,000.00	
1/2/2014	1/8/2014		25,000.00					25,000.00	
		Subtotal - 2013	$ 212,000.00						
3/4/2014	3/6/2014		14,000.00					14,000.00	
4/3/2014	4/30/2014		90,000.00					90,000.00	
6/5/2014	6/18/2014		9,500.00					9,500.00	
11/6/2014	11/14/2014		5,000.00						5,000.00
11/6/2014	11/24/2014		20,000.00						20,000.00
11/6/2014	11/20/2014		12,000.00						12,000.00
11/6/2014	12/1/2014		20,000.00						20,000.00
		Subtotal - 2014	$ 170,500.00						
			$ 1,720,300.00	$ 308,500.00	$ 614,000.00	$ 297,300.00	$ 153,000.00	$ 290,500.00	$ 57,000.00

2014 Penalties Reconciliation	12/31/2014	12/31/2013	Change in 2014
Total Cumulative Penalties - GAAP/PWC Audit	$ 1,720,300.00	$ 1,549,800.00	$ 170,500.00
Total Cumulative Penalties - True Up Report/BP&B	1,372,800.00	1,219,800.00	153,000.00
NERC Unrecognized Penalties[1]	$ 347,500.00	$ 330,000.00	$ 17,500.00

[1] NPCC's audited financial statements include penalties recorded as earned revenue at the time of invoicing, in accordance with GAAP. NPCC's true up report includes only those penalties included in the approved budget for the calendar year, resulting in the difference detailed above.

Northeast Power Coordinating Council, Inc.

Financial Statements
December 31, 2014 and 2013

Northeast Power Coordinating Council, Inc.
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Independent Auditor's Report

To the Board of Directors and the Members of
Northeast Power Coordinating Council, Inc.

We have audited the accompanying financial statements of Northeast Power Coordinating Council, Inc., which comprise the balance sheets as of December 31, 2014 and December 31, 2013, and the related change in net assets and cash flows for the years then ended.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

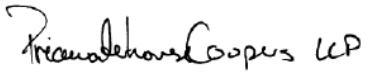
Auditor's Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Northeast Power Coordinating Council, Inc. at December 31, 2014 and December 31, 2013, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.



PricewaterhouseCoopers LLP
New York, New York
March 27, 2015

Northeast Power Coordinating Council, Inc.
Statements of Financial Position
December 31, 2014 and 2013

	2014	2013
Assets		
Cash	$ 5,414,548	$ 7,412,184
Restricted cash	648,796	611,021
Investments	2,211,002	2,210,944
Prepaid expenses	243,624	236,551
Other assets	52,878	137,191
Equipment and leasehold improvements, less accumulated depreciation and amortization of $1,360,479 and $1,100,649, respectively	973,224	1,142,418
Total assets	$ 9,544,072	$ 11,750,309
Liabilities and Net Assets		
Accrued expenses and other liabilities	$ 1,648,827	$ 1,572,583
Accrued liability for pension	18,777	1,135,117
Deferred revenue	994,910	734,117
Deferred rent	740,636	774,268
Total liabilities	3,403,150	4,216,085
Net assets		
Unrestricted net assets	6,140,922	7,534,224
Total net assets	6,140,922	7,534,224
Total liabilities and net assets	$ 9,544,072	$ 11,750,309

The accompanying notes are an integral part of these financial statements.

Northeast Power Coordinating Council, Inc.
Statements of Activities
Years Ended December 31, 2014 and 2013

	2014	2013
Revenue		
Assessments	$ 989,709	$ 1,139,688
Regional entity ERO funding	13,611,880	12,352,264
Penalty sanctions	170,500	212,000
Workshops	62,579	58,650
Interest income	12,291	17,281
Miscellaneous Income	5,245	109,867
Total revenue	14,852,204	13,889,750
Operating expenses		
Salaries and employee benefits	8,586,111	8,365,952
Administrative and consultant fees	2,584,644	2,398,006
Professional fees	587,125	572,229
Meetings and travel	1,042,927	1,131,260
Telephone and telecommunications	219,647	262,232
Office supplies and expense	358,014	316,019
Equipment leases	129,578	131,353
Rent expense	617,862	643,967
Insurance expense	51,020	39,019
Miscellaneous	41,592	43,092
Depreciation and amortization	321,986	300,260
Total operating expenses	14,540,506	14,203,389
Change in net assets before nonoperating expenses	311,698	(313,639)
Nonoperating expenses		
Pension change other than net periodic pension cost	1,705,000	(2,347,593)
(Decrease) increase in net assets	(1,393,302)	2,033,954
Net assets		
Beginning of year	7,534,224	5,500,270
End of year	$ 6,140,922	$ 7,534,224

The accompanying notes are an integral part of these financial statements.

Northeast Power Coordinating Council, Inc.
Statements of Cash Flows
Years Ended December 31, 2014 and 2013

	2014	2013
Cash flows from operating activities		
Change in net assets	$ (1,393,302)	$ 2,033,954
Depreciation and amortization	321,986	300,260
(Increase) decrease in prepaid expenses	(7,073)	34,523
Decrease in other assets	84,313	198,523
Increase in accrued expenses and other liabilities	76,244	285,543
(Decrease) in accrued liability for pension	(1,116,340)	(2,541,036)
Increase in deferred revenue	260,793	498,804
(Decrease) increase in deferred rent	(33,632)	6,367
Net cash (used in) provided by operating activities	(1,807,011)	816,938
Cash flows from investing activities		
Purchases of equipment and leasehold improvements	(152,792)	(168,619)
Purchases of investments	(58)	(50)
Restricted cash	(37,775)	38,929
Net cash (used for) investing activities	(190,625)	(129,740)
Net (decrease) increase in cash	(1,997,636)	687,198
Cash		
Beginning of year	7,412,184	6,724,986
End of year	$ 5,414,548	$ 7,412,184

The accompanying notes are an integral part of these financial statements.

1. Background

Northeast Power Coordinating Council, Inc. ("NPCC" or the "Company") is a New York State not-for-profit corporation whose purpose is to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in Northeastern North America through its regional entity and criteria services divisions. The Company's regional entity division is responsible for the development of regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards, coordination of system planning, design and operations, and assessment of reliability. These responsibilities are pursuant to an agreement with the North American Electric Reliability Corporation ("NERC"), an Electric Reliability Organization ("ERO"), under authority of the U.S. Federal Energy Regulatory Commission ("FERC"), and by Memoranda of Understanding with applicable Canadian Provincial regulatory and/or governmental authorities. The Company's criteria services division establishes regionally-specific criteria, and monitors and enforces compliance with such criteria. In the development of regionally-specific reliability criteria, the Company, to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.

The Company is primarily funded through the NERC based on the regional entity division annual business plan and budget submitted to and approved by the FERC and Canadian provincial regulatory and/or governmental authorities. The Company's criteria services division is funded by regional independent system operators or balancing authority areas and operates on assessments to and funded from these entities based upon a "Net Energy for Load" formula.

2. Summary of Significant Accounting Policies

Basis of Accounting

For the years ended December 31, 2014 and 2013, the Company used the accrual basis of accounting in conformity with accounting principles generally accepted in the United States of America.

Cash

The Company's cash balance consists of its operating checking account, as well as a savings account. At times, cash balances may be in excess of depository insurance limits.

Restricted Cash

Restricted cash represents amounts in deposit accounts funded with penalties levied and received for noncompliance within NPCC U.S., which are required to be used for statutory activities in years subsequent to which the penalty was received, and amounts in deposit accounts for collateralizing a letter of credit as security for NPCC's office lease. At times, cash balances may be in excess of depository insurance limits.

Equipment and Leasehold Improvements

Equipment and leasehold improvements are stated at cost. Depreciation of furniture and computer equipment is computed on the straight-line basis over the estimated useful lives of the applicable assets. Amortization of leasehold improvements is computed on the straight-line basis over the estimated useful lives of the applicable assets, or over the term of the related lease, whichever is less.

Revenue Recognition
For the criteria services division, membership in the Company is on a calendar year basis. There are no fees assessed to full members other than those members that are Independent System Operators or Balancing Authority Areas. Assessments received are recorded as income in the year to which the membership applies irrespective of when billed or collected. For the regional entity division, membership in the Company is on a calendar year basis. There are no fees assessed to general members. Funding mechanisms provided through U.S. regulatory and Canadian governmental and/or regulatory agreements provide for quarterly remittances through the North American Electric Reliability Corporation. Assessments received are recorded as income in the year to which the Business Plan and Budget applies irrespective of when billed or collected. Penalty sanctions are recorded as income when levied and the appeals process has been waived or is concluded.

Rent Expense
The Company's office lease which commenced in 2009 contains predetermined increases and decreases in the rentals payable during the lease term. Rent expense is recognized on a straight-line basis over the lease term. The difference between the rent expense charged to operations during the year and the amount payable under the lease during that year is recorded as "Deferred rent" on the Statements of Financial Position. Deferred rent also includes the landlord's contribution toward the cost of leasehold improvements, which is being amortized over the lease term. The unamortized balance of the landlord's contribution at December 31, 2014 is approximately $336,000.

Income Taxes
The Company has been classified as exempt from federal income taxes under Section 501(c) (6) of the Internal Revenue Code.

Use of Estimates
The Company uses estimates and assumptions in preparing these financial statements in accordance with accounting principles generally accepted in the United States of America. Those estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses. Actual results could vary from the estimates that are used.

3. Investments

The Company's primary banking relationship is with JP Morgan Chase. Prior to 2009, both regional entity (ERO funded) and criteria services (Regional Independent System Operators/Balancing Authority Areas – ISO/BAAs) revenues were invested in a JPMorgan 100% U.S. Treasury Security Money Market Fund (the "Fund"). The Fund aims to provide the highest possible level of current income while still maintaining liquidity and providing maximum safety of principal. The Fund is a money market fund managed to meet the requirements of Rule 2a-7 under the Investment Company Act of 1940. The Fund is not insured or guaranteed by the FDIC or any other government agency. In late 2008, the Fund was closed to additional investments. Subsequent excess cash is being deposited into a savings account with JP Morgan Chase.

The Fund invests solely in debt securities of the U.S. Treasury, including Treasury bills, bonds and notes. These investments carry different interest rates, maturities and issue dates. The National Association of Insurance Commissioner ("NAIC"), Moody's, Fitch IBCA and S&P ratings signify that the Fund has historically had a superior capacity to maintain a net asset value of $1.00 per share. The ratings do not eliminate the risks associated with investing in the Fund. The NAIC "approved" status indicates that the Fund meets certain pricing and quality guidelines. Management has determined that the likelihood of sustaining losses from money market funds to be remote based on the marketability of the underlying investment of the funds.

At December 31, 2014 and 2013, the Company owned 2,211,002 and 2,210,944 units of $1 par value per unit, respectively. In 2014 and 2013, the funds earned average yields of 0%. Investment income earned on the Fund is reinvested into units of the Fund on a monthly basis.

4. Equipment and Leasehold Improvements

Equipment and leasehold improvements at December 31, 2014 and 2013 consists of the following:

	Depreciable Life	2014	2013
Furniture	10 years	$ 202,906	$ 202,906
Computer equipment	3 years	375,949	435,769
Website	3 years	232,000	232,000
Software	3 years	548,157	397,701
Leasehold improvements	15 years (See note 2)	974,691	974,691
		2,333,703	2,243,067
Less: Accumulated depreciation and amortization		(1,360,479)	(1,100,649)
		$ 973,224	$ 1,142,418

In 2014 and 2013, depreciation and amortization expense totaled $321,986 and $300,260, respectively.

5. Pension Plan

The Company has a trusteed, noncontributory defined benefit pension plan (the "Plan") covering employees hired prior to February 6, 2007. In November 2014, the Company decided, subject to Internal Revenue Service and Pension Benefit Guaranty Corporation approval, to terminate the Plan effective January 31, 2015 and freeze all benefits accruals for the Plan's participants effective December 31, 2014. The plan freeze triggered curtailment accounting, which reduced the benefit obligation by $1,421,349 as of December 31, 2014, and resulted in additional 2014 income statement charges of $139,619. The Company's plan contributions were $3,150,000 and $700,000 for the years 2014 and 2013, respectively.

The following tables provide information with respect to the defined benefit plan as of and for the years ended December 31, 2014 and 2013:

	2014	2013
Components of net periodic benefit cost		
Service cost	$ 281,933	$ 298,867
Interest cost	511,899	477,051
Expected return on plan assets	(712,715)	(599,893)
Amortization of prior service cost	20,532	20,532
Recognized actuarial loss	87,391	310,000
Curtailment loss	139,619	-
Net periodic benefit cost	$ 328,659	$ 506,557
Change in benefit obligation		
Benefit obligation at beginning of year	$ 10,293,237	$ 11,279,973
Service cost	281,933	298,867
Interest cost	511,899	477,051
Actuarial (gain)loss	3,186,110	(1,660,662)
Curtailments	(1,421,349)	-
Benefits paid and expected expenses	(103,307)	(101,992)
Benefit obligation at end of year	12,748,523	10,293,237
Change in fair value of plan assets		
Fair value of plan assets at beginning of year	9,158,120	7,603,820
Actual return on plan assets	524,933	956,292
Company contribution	3,150,000	700,000
Benefits paid and actual expenses	(103,307)	(101,992)
Fair value of plan assets at end of year	12,729,746	9,158,120
Funded status at end of year	$ (18,777)	$ (1,135,117)
Amounts recognized in unrestricted net assets consist of		
Loss	$ (5,032,433)	$ (1,745,933)
Prior service cost	-	(160,151)
	$ (5,032,433)	$ (1,906,084)
Changes in unrestricted assets recognized in nonoperating expenses		
Net (gain)/loss	$ 3,373,891	$ (2,017,061)
Amortization of prior service cost	(160,151)	(20,532)
Amortization of net gain/(loss)	(87,391)	(310,000)
	$ 3,126,349	$ (2,347,593)
Amounts of unrestricted net assets expected to be recognized in net periodic benefit cost in 2015		
Amortization of loss	$ 501,011	

	2014	2013
Weighted-average assumptions as of December 31 used for obligation		
Discount rate	4.00 %	5.00 %
Expected return on plan assets	0.00 %	7.50 %
Rate of compensation increase	0.00 %	3.00 %
Weighted-average assumptions as of December 31 used for net periodic benefit cost		
Discount rate	4.00 %	5.00 %
Expected return on plan assets	7.50 %	7.50 %
Rate of compensation increase	3.00 %	3.00 %

The accumulated benefit obligation at December 31, 2014 and 2013 was $12,748,523 and $10,293,237, respectively.

The Company determines its expected return on plan assets assumption by evaluating both historical returns of major asset classes and current market factors. Current market factors include inflation and interest rates, as well as asset diversification.

As a result of the decision to terminate the Plan, all investments were liquidated and all plan assets are being held in cash or cash equivalents as of December 31, 2014.

The Company's defined benefit plan weighted average asset allocation at December 31, 2014 and 2013 by asset category is as follows:

	Allocation Percentage	
	2014	2013
Equity securities	0.0%	70.6%
Debt securities	0.0%	28.0%
Cash	100.0%	1.4%
	100.0%	100.0%

Expected employer contribution for the year ended December 31, 2015 is $460,000.

Benefits expected to be paid in cash in subsequent years ending December 31 are as follows:

2015	$ 98,139
2016	13,686,738
Thereafter	-

6. Savings and Supplemental Plans

The Company maintains a 401(k) plan for which all employees are immediately eligible upon hire. Within this plan, an employee can contribute 2% or greater of his or her compensation up to the IRS limit set for this plan. The Company's policy is to contribute on the employee's behalf 100% of the employee's contribution of the first 3% of his or her compensation, and 50% of his or her contribution for the next 2% of compensation. Additionally, for those employees joining the Company after February 6, 2007, and upon completion of a full calendar year of service, such employees become eligible for a discretionary contribution to be considered annually by the Board of Directors. The discretionary contribution for 2014 and 2013 was 8% of base compensation and totaled $239,139 for 2014 and $189,215 for 2013. Company contributions to the 401(k) plan were $201,834 and $185,546 for 2014 and 2013, respectively. During 2010, the Company adopted a supplemental plan for employees who were not eligible to receive the same percentage level of retirement benefits as other employees under the 401(k) plan due to IRS compensation limits. The Company contributed $29,300 and $26,500 to this supplemental plan for 2014 and 2013, respectively. During 2013, the Company adopted a 457(f) plan for the President and CEO to provide benefits not provided under the Pension Plan as a result of the IRS code limitations. The Company contributed $30,000 to this plan for each of the years 2014 and 2013.

7. Leases

The Company is obligated under long-term operating leases for the rental of office facilities and certain equipment. NPCC executed office and equipment leases with effective rental dates starting in 2009 coordinated with its relocation of offices within New York City. NPCC's office lease provides for additional rent based on increases in real estate taxes and operating expenses over base amounts. The office lease expires on April 30, 2024 and includes an option to renew for five years. The office lease provides for security in the form of a collateralized letter of credit in the amount of $500,000 at lease inception and reduced to $300,000 at December 31, 2012, and reduced amounts in future years. NPCC executed various computer and equipment leases with expiration dates through 2017. In addition, the Company rents certain other equipment on a month-to-month basis. Rental expense for office facilities and equipment totaled $747,440 and $775,320 for 2014 and 2013, respectively.

Future minimum rental payments required under the Company's long-term operating leases as of December 31, 2014 are as follows:

	Office Space	Other Leases	Total
Year Ending December 31			
2015	$ 672,392	$ 103,332	$ 775,724
2016	672,392	34,838	707,230
2017	672,392	14,696	687,088
2018	672,392	-	672,392
2019	704,392	-	704,392
Thereafter	3,121,699	-	3,121,699
	$ 6,515,659	$ 152,866	$ 6,668,525

8. Functional Expenses

During 2014 and 2013 salaries and employee benefits consist of the following:

	2014	2013
President, COO and technical staff	$ 5,943,449	$ 5,510,411
Administrative support	183,120	175,493
Payroll taxes, insurance, pension and educational assistance	2,459,542	2,680,048
Total salaries and employee benefits	$ 8,586,111	$ 8,365,952

9. Other Expenses

The Company incurs various costs for administrative, consultant and professional services. Such costs amounted to $3,171,769 and $2,970,235 in 2014 and 2013, respectively, and consist of the following:

	2014	2013
Consultants	$ 1,805,738	$ 1,734,733
Accounting, legal and other services	1,313,535	1,197,113
Pension administration	52,496	38,389
Total administrative, consultant and professional fees	$ 3,171,769	$ 2,970,235

These costs are reflected in “Administrative and consultant fees” and “Professional fees” in the Statements of Activities.

10. Related Party Transactions

The NERC, through agreements with the FERC in the U.S. and Canadian Provincial regulatory and/or governmental agreements within Canada, delegates enforcement authority to eight Regional Entities. NPCC is the cross-border regional entity for Northeastern North America. NERC was certified as the “Electric Reliability Organization” by the FERC on July 20, 2006. As of June 18, 2007, the U.S. FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. NERC relies on the diverse and collective expertise of industry participants to improve the reliability of the bulk power system. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. NERC is subject to audit by the U.S. FERC and governmental and/or regulatory authorities in Canada. NERC funded the Regional Entities based upon Business Plans and Budgets submitted to and approved by FERC in the U.S. and Canadian regulatory and/or governmental authorities.

NPCC’s criteria services division was fully funded by regional independent system operator or balancing authority areas and operated on assessments to and funded from these six entities. Dues were based upon a “Net Energy for Load” funding formula. During 2014 and 2013, total assessments billed amounted to $989,709 and $1,139,688, respectively.

Description	2014 Percent	2014 Total Share	2013 Percent	2013 Total Share
Hydro-Quebec TransEnergie	28.82 %	$ 285,198	28.56 %	$ 325,481
Independent Electricity System Operator	22.03 %	218,018	21.94 %	250,013
ISO-New England, Inc.	19.97 %	197,640	20.65 %	235,313
New Brunswick System Operator	2.17 %	21,458	2.12 %	24,185
New York Independent System Operator	25.39 %	251,279	24.91 %	283,927
Nova Scotia Power Inc.	1.62 %	16,116	1.82 %	20,769
Total assessments	100.00 %	$ 989,709	100.00 %	$ 1,139,688

11. Line of Credit

On March 18, 2013, pursuant to an agreement with a lender, the Company obtained a line of credit in the amount of $1,000,000. The line of credit, which had an initial term of 18 months, was renewed on September 18, 2014 for one year. Outstanding borrowings are secured by all of the Company's assets. There were no borrowings against the line of credit as of December 31, 2014 and 2013.

12. Subsequent Events

Management has evaluated, for potential recognition and disclosure, events subsequent to the date of the Statement of Financial Position through March 27, 2015, the date the financial statements were available to be issued.

ATTACHMENT 5

2014 ACTUAL COST-TO-BUDGET COMPARISON

AND

2014 AUDITED FINANCIAL REPORT

FOR

RELIABILITYFIRST CORPORATION

Jill S. Lewton
Controller
3 Summit Park, Suite 600
Cleveland Drive, OH 44131
Office: 216.503.0600
Jill.lewton@rfirst.org

May 11, 2015

Mr. Michael Walker
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, Georgia 30326

Re: ReliabilityFirst's 2014 Actual Cost-To-Budget Comparison

Dear Mr. Michael Walker:

As requested, ReliabilityFirst Corporation (ReliabilityFirst) is providing NERC the end of year audited 2014 Actual Cost-To-Budget Comparison. A summary of significant variances are explained in the Introduction Section, while more detailed explanations of variances are provided by program area.

The explanations of variances are provided based on the following criteria:

1. Variances equal to or greater than +/- 10% of budget, and
2. Variances greater than $10,000, or
3. Variances that are considered significant.

For more information, please contact me at 216.503.0600 or jill.lewton@rfirst.org.

Very truly yours,

RELIABILITYFIRST CORPORATION

Jill S. Lewton

Jill S. Lewton
Controller

Introduction

This Actual Cost-To-Budget Comparison includes a summary of significant variances, followed by more detailed analyses by program areas. In 2014, ReliabilityFirst performed only statutory activities, and therefore all funding and expenses shown are for those functions delegated to ReliabilityFirst by the ERO. The financial information included in this comparison is based on the results of ReliabilityFirst's 2014 independent audit that was performed by McGladrey LLP and completed on April 30, 2015.

For the year ending December 31, 2014, ReliabilityFirst Corporation was $1,599K (9%) over budget. This variance included $1,692K of office costs, office relocation, computer hardware & software, furniture & fixtures, and leasehold improvement expenses associated with the March 2014 office and data center relocation, which were not included in the 2014 budget. Without these expenses, the year ending variance was $93K (.51%) under budget.

Funding

The variance in Investment Income was due to the unrealized change in the value of the company's investment portfolio. This variance is reflected in each direct program as a result of it being allocated proportionately based on FTE count to the direct programs.

The variance in Miscellaneous Income was due to the corporate credit card points that were redeemed for cash and used to help offset the office relocation expenses. This variance is reflected in each direct program as a result of it being allocated proportionately based on FTE count to the direct programs.

Budget Expenses

Personnel Expenses

Salaries, Benefits, and Retirement Costs were under budget due to personnel variances below the approved staffing levels.

Payroll Taxes was over budget due to a prior year tax rate adjustment and additional tax payments that occurred at the end of the year.

Meeting Expenses

Meeting expenses were over budget due to a higher than expected attendance and associated costs experienced at the Compliance and CIP V5 Workshops.

Operating Expenses

Consultants & Contracts was under budget as a result of more effective utilization of staff resources, therefore there was less need to utilize contractors for compliance work.

Office Rent was over budget due to the straight line rent for the new office lease which was not included in the budget.

Professional Services was over budget due to the fees associated with the search for a new independent director.

Depreciation expense directly correlates to current fixed asset activities. Therefore, as a result of the fixed assets purchased for the office move more depreciation was being calculated than budgeted.

Non-Operating Expenses

The variance in Non-Operating Expenses was due to the expenses incurred to physically move the office, along with the losses recorded for the fixed assets that were written off or disposed of as a result of the office move.

Fixed Assets

Computer Hardware & Software was over budget as a result of the hardware and software purchases made for the new office.

The variance in Furniture & Fixtures was a result of the purchase of office furniture for staff offices, conference rooms, and common areas for the new office.

The variance in Leasehold Improvements was a result of the improvements made to the new office.

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
ReliabilityFirst Corporation

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ 15,159,784	$ 15,159,784	$ 0	0.00%
Penalty Sanctions	1,358,133	1,358,133	0	0.00%
Total ReliabilityFirst Funding	**$ 16,517,917**	**$ 16,517,917**	**$ 0**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	45,242	-	45,242	0.00%
Miscellaneous	43,600	-	43,600	0.00%
Total Funding	**$ 16,606,759**	**$ 16,517,917**	**$ 88,842**	**0.54%**
Expenses				
Personnel Expenses				
Salaries	$ 10,472,419	$ 10,674,551	$ (202,132)	-1.89%
Payroll Taxes	659,647	646,319	13,328	2.06%
Benefits	1,337,200	1,405,661	(68,461)	-4.87%
Retirement Costs	1,580,279	1,659,567	(79,288)	-4.78%
Total Personnel Expenses	**$ 14,049,545**	**$ 14,386,098**	**$ (336,553)**	**-2.34%**
Meeting Expenses				
Meetings	$ 190,975	$ 149,980	$ 40,995	27.33%
Travel	726,748	788,600	(61,852)	-7.84%
Conference Calls	43,927	38,400	5,527	14.39%
Total Meeting Expenses	**$ 961,650**	**$ 976,980**	**$ (15,330)**	**-1.57%**
Operating Expenses				
Consultants & Contracts	$ 405,260	$ 627,597	$ (222,337)	-35.43%
Office Rent	752,182	504,952	247,230	48.96%
Office Costs	1,047,255	981,284	65,971	6.72%
Professional Services	562,388	460,732	101,656	22.06%
Miscellaneous	39,749	34,555	5,194	15.03%
Depreciation	425,232	319,433	105,799	33.12%
Total Operating Expenses	**$ 3,232,066**	**$ 2,928,553**	**$ 303,513**	**10.36%**
Total Direct Expenses	**$ 18,243,261**	**$ 18,291,631**	**$ (48,370)**	**-0.26%**
Indirect Expenses	**$ (0)**	**$ 1**	**$ (1)**	**-100.00%**
Non-Operating Expenses	198,399	-	198,399	0.00%
Total Expenses	**$ 18,441,660**	**$ 18,291,632**	**$ 150,028**	**0.82%**
Change in Assets	**$ (1,834,901)**	**$ (1,773,716)**	**$ (61,185)**	**3.45%**
Fixed Assets				
Depreciation	$ (425,232)	$ (319,433)	$ (105,799)	33.12%
Computer Hardware & Software CapEx	185,178	91,000	94,178	103.49%
Furniture & Fixtures CapEx	123,701	-	123,701	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	1,337,374	-	1,337,374	0.00%
	$ 1,221,021	$ (228,433)	$ 1,449,454	-634.52%
Allocation of Fixed Assets	0	-	$ 0	0.00%
Inc/(Dec) in Fixed Assets	**$ 1,221,021**	**$ (228,433)**	**$ 1,449,454**	**-634.52%**
Total Budget	**$ 19,662,681**	**$ 18,063,199**	**$ 1,599,482**	**8.85%**
Total Change in Working Capital	**$ (3,055,922)**	**$ (1,545,283)**	**$ (1,510,639)**	**97.76%**
WC - 12/31/2013	1,167,190	1,545,283	(378,093)	
Change in reserves from current year operations	(3,055,922)	(1,545,283)	(1,510,639)	
Other Adjustments to Reserves	1,474,752	0	1,474,752	
	(413,980)	0	(413,981)	
Operating Reserve	1,000,000	1,000,000	-	
Total Working Capital and Operating Reserve	**586,020**	**1,000,000**	**(413,981)**	
FTEs	**69.23**	**72.00**	**(2.77)**	**-3.85%**

Cost Allocation

ReliabilityFirst records all direct costs to the appropriate program areas. Costs related to the Administrative Services programs (Indirect Expenses) are allocated proportionately based on FTE count to the direct programs.

- Direct Programs include:
  - Standards
  - Compliance
  - Reliability Assessment
  - Training & Education
  - Situation Awareness
- Administrative Services Programs include:
  - General & Administrative
  - Legal & Regulatory Affairs
  - Information Technology
  - Human Resources
  - Finance & Accounting

Cash Reserves

ReliabilityFirst's Operating Reserve of $1,000,000 was utilized in 2014 in the amount of $414K. An inaccuracy occurred during the 2014 assessment calculation that resulted in the assessment being lower than what was necessary. Therefore, ReliabilityFirst had to draw from the operating reserve to fund the day to day operations.

Major Accomplishments

All statutory objectives were satisfied, including these major accomplishments:

- Developed and trained stakeholders in the Internal Controls Evaluation (ICE) and Inherit Risk Assessment (IRA) guides – Reliability Assurance Initiative (RAI)
- Completed 79 audits monitoring CIP, Operations, and Planning Standards
- Performed assist visits at 19 Entities focusing on CIP Version 5 implementation, along with creating and implementing robust mitigation plans, and discussing registered function compliance responsibilities
- Performed three organization certifications
  - Changing a BA footprint into two BA footprints
  - Integration of transmission facilities into an entity's RC footprint
  - BA and TOP certification for a registered entity's newly built control center
- Conducted two Reliability Workshops including over 400 people focusing on RAI topics and guidance on transitioning from the CIP V3 to CIP V5, along with monthly outreach calls averaging 80 people per call

- Reviewed and accepted 124 mitigation plans and verified the completion of approximately 176 mitigation plans
- Worked with Registered Entities on 38 event analysis reports and published four Lessons Learned arising from event analysis reports in the region
- Registered 15 new entities and determined that 17 Entities no longer met the criteria for certain functions and facilitated their removal from Registry
- Processed self-certifications covering 55 Standards, receiving 4,663 self-certifications covering 12,342 Standard Requirements from 342 entities
- Posted 20 periodic data submittals covering 20 Standards and received data from 233 entities
- Performed analysis to determine cause of high misoperation rate including those from events and provided power line carrier misoperation training to the Protection Subcommittee
- Led a successful pilot of the self-logging program with a large entity and the TRE and SPP regions which significantly shaped the current ERO-wide self-logging program
- Identified and established action plans for corporate risks

Reliability Standards Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Reliability Standards

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
Reliability*First* Funding				
ERO Assessments	$ 182,202	$ 182,202	$ 0	0.00%
Penalty Sanctions	11,872	11,872	0	0.00%
Total Reliability*First* Funding	**$ 194,074**	**$ 194,074**	**$ 0**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	106	-	106	0.00%
Miscellaneous	102	-	102	0.00%
Total Funding	**$ 194,282**	**$ 194,074**	**$ 209**	**0.11%**
Expenses				
Personnel Expenses				
Salaries	$ 8,854	$ 102,707	$ (93,853)	-91.38%
Payroll Taxes	1,876	5,794	(3,918)	-67.62%
Benefits	2,688	11,195	(8,507)	-75.99%
Retirement Costs	4,856	14,462	(9,606)	-66.42%
Total Personnel Expenses	**$ 18,274**	**$ 134,158**	**$ (115,884)**	**-86.38%**
Meeting Expenses				
Meetings	$ -	$ -	$ -	0.00%
Travel	2,114	12,000	(9,886)	-82.38%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 2,114**	**$ 12,000**	**$ (9,886)**	**-82.38%**
Operating Expenses				
Consultants & Contracts	$ -	$ -	$ -	0.00%
Office Rent	-	-	-	0.00%
Office Costs	575	2,513	(1,938)	-77.12%
Professional Services	-	-	-	0.00%
Miscellaneous	180	-	180	0.00%
Depreciation	-	-	-	0.00%
Total Operating Expenses	**$ 755**	**$ 2,513**	**$ (1,758)**	**-69.96%**
Total Direct Expenses	**$ 21,143**	**$ 148,671**	**$ (127,528)**	**-85.78%**
Indirect Expenses	**$ 14,461**	**$ 46,452**	**$ (31,991)**	**-68.87%**
Non-Operating Expenses	**$ -**	**$ -**	**$ -**	0.00%
Total Expenses	**$ 35,604**	**$ 195,123**	**$ (159,520)**	**-81.75%**
Change in Assets	**$ 158,679**	**$ (1,050)**	**$ 159,728**	**-15218.31%**
Fixed Assets				
Depreciation	$ -	$ -	$ -	0.00%
Computer Hardware & Software CapEx	-	-	-	0.00%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	-	-	-	0.00%
	$ -	$ -	$ -	0.00%
Allocation of Fixed Assets	$ (3,097)	$ (1,050)	$ (2,047)	194.95%
Inc/(Dec) in Fixed Assets	**$ (3,097)**	**$ (1,050)**	**$ (2,047)**	**194.95%**
Total Budget	**$ 32,507**	**$ 194,073**	**$ (161,567)**	**-83.25%**
Total Change in Working Capital	**$ 161,776**	**$ 0**	**$ 161,775**	**38414768.51%**
FTEs	**0.13**	**0.50**	**(0.37)**	**-74.00%**

Explanation of Variances - Reliability Standards Program

The expenses in the Reliability Standards Program were under budget due to the reallocation of staff to the Reliability Assurance and Compliance Monitoring Program to support the reorganization that was necessary to advance the Reliability Assurance initiatives.

Compliance Monitoring and Enforcement, and Organization Registration and Certification

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Compliance Monitoring and Enforcement, and Organization Registration and Certification

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ 12,563,972	$ 12,563,972	$ -	0.00%
Penalty Sanctions	1,020,974	1,020,974	-	0.00%
Total ReliabilityFirst Funding	**$ 13,584,946**	**$ 13,584,946**	**$ -**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	35,832	-	35,832	0.00%
Miscellaneous	34,531	-	34,531	0.00%
Total Funding	**$ 13,655,309**	**$ 13,584,946**	**$ 70,363**	**0.52%**
Expenses				
Personnel Expenses				
Salaries	$ 6,341,716	$ 6,071,377	$ 270,339	4.45%
Payroll Taxes	409,083	380,483	28,600	7.52%
Benefits	848,821	869,013	(20,192)	-2.32%
Retirement Costs	896,015	950,486	(54,471)	-5.73%
Total Personnel Expenses	**$ 8,495,635**	**$ 8,271,359**	**$ 224,276**	**2.71%**
Meeting Expenses				
Meetings	$ 14,402	$ 10,730	$ 3,672	34.22%
Travel	484,269	533,000	(48,731)	-9.14%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 498,671**	**$ 543,730**	**$ (45,059)**	**-8.29%**
Operating Expenses				
Consultants & Contracts	$ 160,801	$ 454,000	$ (293,199)	-64.58%
Office Rent	-	-	-	0.00%
Office Costs	274,668	381,527	(106,859)	-28.01%
Professional Services	-	15,000	(15,000)	-100.00%
Miscellaneous	505	2,721	(2,216)	-81.44%
Depreciation	118,617	119,909	(1,292)	-1.08%
Total Operating Expenses	**$ 554,591**	**$ 973,157**	**$ (418,566)**	**-43.01%**
Total Direct Expenses	**$ 9,548,897**	**$ 9,788,246**	**$ (239,349)**	**-2.45%**
Indirect Expenses	**$ 4,887,672**	**$ 3,994,892**	**$ 892,780**	**22.35%**
Non-Operating Expenses	**$ -**	**$ -**	**$ -**	0.00%
Total Expenses	**$ 14,436,569**	**$ 13,783,138**	**$ 653,431**	**4.74%**
Change in Assets	**$ (781,260)**	**$ (198,192)**	**$ (583,068)**	**294.19%**
Fixed Assets				
Depreciation	(118,617)	(119,909)	1,292	-1.08%
Computer Hardware & Softwar	13,608	12,000	1,608	13.40%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	-	-	-	0.00%
	(105,009)	(107,909)	2,900	-2.69%
Allocation of Fixed Assets	$ (1,046,791)	$ (90,284)	$ (956,507)	1059.44%
Inc/(Dec) in Fixed Assets	**$ (1,151,800)**	**$ (198,193)**	**$ (953,607)**	**481.15%**
Total Budget	**$ 13,284,768**	**$ 13,584,945**	**$ (300,177)**	**-2.21%**
Total Change in Working Capital	**$ 370,540**	**$ 1**	**$ 370,539**	**37053936.11%**
FTEs	**43.94**	**43.00**	**0.94**	**2.19%**

Explanation of Variances - Compliance Monitoring and Enforcement, and Organization Registration and Certification

Personnel Expenses

Salaries and Payroll Taxes were over budget due to the reallocation of staff to support the reorganization that was necessary to advance the Reliability Assurance initiatives.

Benefits was under budget due to medical benefits being less than budgeted.

Retirement Costs was under budget due to the year end adjustment that was made to reduce the discretionary contribution amount for those employees who did not meet the plan requirements.

Operating Expenses

Consultants and Contracts expenses were under budget as a result of more effective utilization of staff resources, therefore there was less need to utilize contractors for compliance work.

Office Costs was under budget as a result of changing the company wireless plan to a data share plan, along with having less change orders for the compliance portal and lower maintenance fees for the audit management software.

Professional Services was under budget due to the non-renewal of a retainer agreement for a hearing officer.

Indirect Expenses

Indirect Expenses are expenses related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs. As a result, the variance was due to higher administrative expenditures being allocated.

Allocation of Fixed Assets

Allocation of Fixed Assets are fixed asset costs related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs.

Reliability Assessment and Performance Analysis Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Reliability Assessment and Performance Analysis

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ 2,883,895	$ 2,883,895	$ -	0.00%
Penalty Sanctions	237,436	237,436	-	0.00%
Total ReliabilityFirst Funding	**$ 3,121,331**	**$ 3,121,331**	**$ -**	**0.00%**
Membership Dues			$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	6,352	-	6,352	0.00%
Miscellaneous	6,122	-	6,122	0.00%
Total Funding	**$ 3,133,805**	**$ 3,121,331**	**$ 12,474**	**0.40%**
Expenses				
Personnel Expenses				
Salaries	$ 1,208,251	$ 1,495,659	$ (287,408)	-19.22%
Payroll Taxes	79,143	90,649	(11,506)	-12.69%
Benefits	121,429	150,700	(29,271)	-19.42%
Retirement Costs	196,167	236,514	(40,347)	-17.06%
Total Personnel Expenses	**$ 1,604,990**	**$ 1,973,522**	**$ (368,532)**	**-18.67%**
Meeting Expenses				
Meetings	$ 12,487	$ 22,000	$ (9,513)	-43.24%
Travel	89,620	85,500	4,120	4.82%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 102,107**	**$ 107,500**	**$ (5,393)**	**-5.02%**
Operating Expenses				
Consultants & Contracts	$ 80,766	$ 77,097	$ 3,669	4.76%
Office Rent	-	-	-	0.00%
Office Costs	59,765	54,963	4,802	8.74%
Professional Services	-	-	-	0.00%
Miscellaneous	-	200	(200)	-100.00%
Depreciation	-	-	-	0.00%
Total Operating Expenses	**$ 140,531**	**$ 132,260**	**$ 8,271**	**6.25%**
Total Direct Expenses	**$ 1,847,628**	**$ 2,213,282**	**$ (365,654)**	**-16.52%**
Indirect Expenses	**$ 866,522**	**$ 929,045**	**$ (62,523)**	**-6.73%**
Non-Operating Expenses	**$ -**	**$ -**	**$ -**	0.00%
Total Expenses	**$ 2,714,150**	**$ 3,142,327**	**$ (428,177)**	**-13.63%**
Change in Assets	**$ 419,656**	**$ (20,996)**	**$ 440,652**	**-2098.74%**
Fixed Assets				
Depreciation	-	-	-	0.00%
Computer Hardware & Software	-	-	-	0.00%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	-	-	-	0.00%
	-	-	-	0.00%
Allocation of Fixed Assets	$ (185,583)	$ (20,996)	$ (164,587)	783.90%
Inc/(Dec) in Fixed Assets	**$ (185,583)**	**$ (20,996)**	**$ (164,587)**	**783.90%**
Total Budget	**$ 2,528,567**	**$ 3,121,331**	**$ (592,764)**	**-18.99%**
Total Change in Working Capital	**$ 605,238**	**$ -**	**$ 605,238**	**0.00%**
FTEs	**7.79**	**10.00**	**(2.21)**	**-22.10%**

Explanation of Variances - Reliability Assessment and Performance Analysis Program

Personnel Expenses

Personnel expenses were under budget due to the reallocation of staff to support the reorganization that was necessary to advance the Reliability Assurance initiatives.

Allocation of Fixed Assets

Allocation of Fixed Assets are fixed asset costs related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs.

Training, Education and Operator Certification Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Training, Education, and Operator Certification Program

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ 842,748	$ 842,748	$ -	0.00%
Penalty Sanctions	73,605	73,605	-	0.00%
Total ReliabilityFirst Funding	**$ 916,353**	**$ 916,353**	**$ -**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	2,463	-	2,463	0.00%
Miscellaneous	2,373	-	2,373	0.00%
Total Funding	**$ 921,189**	**$ 916,353**	**$ 4,836**	**0.53%**
Expenses				
Personnel Expenses				
Salaries	$ 419,181	$ 428,516	$ (9,335)	-2.18%
Payroll Taxes	29,786	28,687	1,099	3.83%
Benefits	56,625	53,484	3,141	5.87%
Retirement Costs	66,761	67,571	(810)	-1.20%
Total Personnel Expenses	**$ 572,353**	**$ 578,258**	**$ (5,905)**	**-1.02%**
Meeting Expenses				
Meetings	$ 83,110	$ 45,000	$ 38,110	84.69%
Travel	6,791	11,600	(4,809)	-41.46%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 89,901**	**$ 56,600**	**$ 33,301**	**58.84%**
Operating Expenses				
Consultants & Contracts	$ -	$ -	$ -	0.00%
Office Rent	-	-	-	0.00%
Office Costs	15	-	15	0.00%
Professional Services	-	-	-	0.00%
Miscellaneous	-	-	-	0.00%
Depreciation	-	-	-	0.00%
Total Operating Expenses	**$ 15**	**$ -**	**$ 15**	**0.00%**
Total Direct Expenses	**$ 662,269**	**$ 634,858**	**$ 27,411**	**4.32%**
Indirect Expenses	**$ 335,930**	**$ 288,004**	**$ 47,926**	**16.64%**
Non-Operating Expenses	**$ -**	**$ -**	**$ -**	0.00%
Total Expenses	**$ 998,199**	**$ 922,862**	**$ 75,337**	**8.16%**
Change in Assets	**$ (77,010)**	**$ (6,509)**	**$ (70,501)**	**1083.13%**
Fixed Assets				
Depreciation	-	-	-	0.00%
Computer Hardware & Softwar	-	-	-	0.00%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	-	-	-	0.00%
	-	-	-	0.00%
Allocation of Fixed Assets	$ (71,946)	$ (6,509)	$ (65,437)	1005.33%
Inc/(Dec) in Fixed Assets	**$ (71,946)**	**$ (6,509)**	**$ (65,437)**	**1005.33%**
Total Budget	**$ 926,253**	**$ 916,353**	**$ 9,900**	**1.08%**
Total Change in Working Capital	**$ (5,064)**	**$ -**	**$ (5,064)**	**0.00%**
FTEs	**3.02**	**3.10**	**(0.08)**	**-2.58%**

Explanation of Variances - Training, Education and Operator Certification Program

Personnel Expenses

Salaries was under budget due to a yearend banked vacation adjustment.

Payroll Taxes was over budget due to a prior year tax rate adjustment and additional tax payments that occurred at the end of the year.

Benefits was over budget due to several workers compensation adjustments.

Retirement costs was under budget due to employees not taking full advantage of the company plan benefits.

Meeting Expenses

Meetings was over budget due to a higher than expected attendance and associated costs experienced at the Compliance and CIP V5 Workshops.

Indirect Expenses

Indirect Expenses are expenses related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs. As a result, the variance was due to higher administrative expenditures being allocated.

Allocation of Fixed Assets

Allocation of Fixed Assets are fixed asset costs related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs.

Situation Awareness and Infrastructure Security Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Situation Awareness and Infrastructure Security

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ 232,251	$ 232,251	$ -	0.00%
Penalty Sanctions	14,246	14,246	-	0.00%
Total ReliabilityFirst Funding	**$ 246,497**	**$ 246,497**	**$ -**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	489	-	489	0.00%
Miscellaneous	472	-	472	0.00%
Total Funding	**$ 247,458**	**$ 246,497**	**$ 961**	**0.39%**
Expenses				
Personnel Expenses				
Salaries	$ 111,642	$ 123,160	$ (11,518)	-9.35%
Payroll Taxes	6,697	6,112	585	9.57%
Benefits	10,766	7,265	3,501	48.19%
Retirement Costs	18,791	19,593	(802)	-4.09%
Total Personnel Expenses	**$ 147,896**	**$ 156,130**	**$ (8,234)**	**-5.27%**
Meeting Expenses				
Meetings	$ 4,823	$ 7,000	$ (2,177)	-31.10%
Travel	26,087	25,000	1,087	4.35%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 30,910**	**$ 32,000**	**$ (1,090)**	**-3.41%**
Operating Expenses				
Consultants & Contracts	$ 5,000	$ -	$ 5,000	0.00%
Office Rent	-	-	-	0.00%
Office Costs	6,019	3,036	2,983	98.25%
Professional Services	-	-	-	0.00%
Miscellaneous	67	848	(781)	-92.10%
Depreciation	506	425	81	19.06%
Total Operating Expenses	**$ 11,592**	**$ 4,309**	**$ 7,283**	**169.02%**
Total Direct Expenses	**$ 190,398**	**$ 192,439**	**$ (2,041)**	**-1.06%**
Indirect Expenses	**$ 66,741**	**$ 55,743**	**$ 10,998**	**19.73%**
Non-Operating Expenses	**$ -**	**$ -**	**$ -**	0.00%
Total Expenses	**$ 257,139**	**$ 248,182**	**$ 8,957**	**3.61%**
Change in Assets	**$ (9,681)**	**$ (1,685)**	**$ (7,996)**	**474.56%**
Fixed Assets				
Depreciation	(506)	(425)	(81)	19.06%
Computer Hardware & Software	4,825	-	4,825	0.00%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	-	-	-	0.00%
	4,319	(425)	4,744	-1116.24%
Allocation of Fixed Assets	$ (14,294)	$ (1,260)	$ (13,034)	1034.44%
Inc/(Dec) in Fixed Assets	**$ (9,975)**	**$ (1,685)**	**$ (8,290)**	**491.98%**
Total Budget	**$ 247,164**	**$ 246,497**	**$ 667**	**0.27%**
Total Change in Working Capital	**$ 294**	**$ -**	**$ 294**	**0.00%**
FTEs	**0.60**	**0.60**	**0.00**	**0.00%**

Explanation of Variances - Situation Awareness and Infrastructure Security Program

Personnel Expenses

Salaries and Retirement Costs were under budget due to the various resource reallocations that occurred during the first quarter of the year.

Payroll Taxes was over budget due to a prior year tax rate adjustment and additional tax payments that occurred at the end of the year.

Benefits was over budget due to additional employee training that was taken along with changes in an employee's medical plan.

Operating Expenses

The variance in Consultants and Contracts was a result of executive coaching services that were not budgeted.

Fixed Assets

The variance in Computer Hardware was due to the purchase of hardware for the Situational Awareness room.

Indirect Expenses

Indirect Expenses are expenses related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs. As a result, the variance was due to higher administrative expenditures being allocated.

Allocation of Fixed Assets

Allocation of Fixed Assets are fixed asset costs related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs.

General and Administrative Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
General and Administrative

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ (1,545,284)	$ (1,545,284)	$ -	0.00%
Penalty Sanctions			-	0.00%
Total ReliabilityFirst Funding	**$ (1,545,284)**	**$ (1,545,284)**	**$ -**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	-	-	-	0.00%
Miscellaneous	-	-	-	0.00%
Total Funding	**$ (1,545,284)**	**$ (1,545,284)**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	$ 1,118,071	$ 1,134,062	$ (15,991)	-1.41%
Payroll Taxes	48,857	46,893	1,964	4.19%
Benefits	66,377	68,963	(2,586)	-3.75%
Retirement Costs	152,848	155,262	(2,414)	-1.55%
Total Personnel Expenses	**$ 1,386,153**	**$ 1,405,180**	**$ (19,027)**	**-1.35%**
Meeting Expenses				
Meetings	$ 64,513	$ 47,500	$ 17,013	35.82%
Travel	50,311	57,500	(7,189)	-12.50%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 114,824**	**$ 105,000**	**$ 9,824**	**9.36%**
Operating Expenses				
Consultants & Contracts	$ 53,608	$ 59,500	$ (5,892)	-9.90%
Office Rent	699,024	404,952	294,072	72.62%
Office Costs	142,365	71,057	71,308	100.35%
Professional Services	427,060	302,400	124,660	41.22%
Miscellaneous	15,304	11,876	3,428	28.86%
Depreciation	160,927	41,920	119,007	283.89%
Total Operating Expenses	**$ 1,498,288**	**$ 891,705**	**$ 606,583**	**68.03%**
Total Direct Expenses	**$ 2,999,265**	**$ 2,401,885**	**$ 597,380**	**24.87%**
Indirect Expenses	**$ (3,127,218)**	**$ (2,401,885)**	**$ (725,333)**	**30.20%**
Non-Operating Expenses	**$ 127,953**	**$ -**	**$ 127,953**	0.00%
Total Expenses	**$ -**	**$ -**	**$ -**	**0.00%**
Change in Assets	**$ (1,545,284)**	**$ (1,545,284)**	**$ -**	**0.00%**
Fixed Assets				
Depreciation	(160,927)	(41,920)	(119,007)	283.89%
Computer Hardware & Software	-	-	-	0.00%
Furniture & Fixtures CapEx	123,701		123,701	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	1,099,493		1,099,493	0.00%
	1,062,267	(41,920)	1,104,187	-2634.03%
Allocation of Fixed Assets	$ 1,062,267	$ 41,920	$ 1,020,347	2434.03%
Inc/(Dec) in Fixed Assets	**$ 2,124,533**	**$ -**	**$ 2,124,533**	**0.00%**
Total Budget	**$ 2,124,533**	**$ -**	**$ 2,124,533**	**0.00%**
Total Change in Working Capital	**$ (3,669,817)**	**$ (1,545,284)**	**$ (2,124,533)**	**137.48%**
FTEs	**3.32**	**3.30**	**0.02**	**0.61%**

Explanation of Variances - General and Administrative Program

Funding Source

The ERO Assessment amount was additional funds from the prior year used to reduce the overall 2014 assessment.

Personnel Expenses

Payroll Taxes was over budget due to a prior year tax rate adjustment and additional tax payments that occurred at the end of the year.

Meeting Expenses

Meetings was over budget primarily due to the board meeting costs being higher than expected.

Operating Expense

Office Rent was over budget due to the straight line rent that was being recorded for the new office lease that was not included in the budget.

Office Costs was over budget as a result of the purchase of office furniture for staff offices, conference rooms, and common areas for the new office.

Professional Services was over budget due to the fees associated with the search for a new independent director.

Depreciation expense directly correlates to fixed asset activities. Therefore, as a result of the fixed assets purchased for the office move more depreciation was being calculated than budgeted.

Indirect Expenses

Indirect Expenses are expenses related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs. As a result, the variance was due to higher General and Administrative expenditures being allocated.

Non-Operating Expenses

The variance in Non-Operating expenses was due to the expenses incurred to physically move the office, along with the losses recorded for the leasehold improvements from the old office that were written off.

Fixed Assets

The variance in Furniture & Fixtures was a result of the purchase of office furniture for staff offices, conference rooms, and common areas for the new office.

The variance in Leasehold Improvements was a result of the improvements made to the new office.

Legal and Regulatory Affairs Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Legal and Regulatory Affairs

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ -	$ -	$ -	0.00%
Penalty Sanctions			-	0.00%
Total ReliabilityFirst Funding	**$ -**	**$ -**	**$ -**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	-	-	-	0.00%
Miscellaneous	-	-	-	0.00%
Total Funding	**$ -**	**$ -**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	$ 465,904	$ 399,449	$ 66,455	16.64%
Payroll Taxes	22,426	20,114	2,312	11.49%
Benefits	31,179	28,452	2,727	9.58%
Retirement Costs	67,287	62,462	4,825	7.72%
Total Personnel Expenses	**$ 586,796**	**$ 510,477**	**$ 76,319**	**14.95%**
Meeting Expenses				
Meetings	$ 167	$ -	$ 167	0.00%
Travel	44,992	38,000	6,992	18.40%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 45,159**	**$ 38,000**	**$ 7,159**	**18.84%**
Operating Expenses				
Consultants & Contracts	$ 5,000	$ 5,000	$ -	0.00%
Office Rent	-	-	-	0.00%
Office Costs	16,253	15,655	598	3.82%
Professional Services	48,801	65,000	(16,199)	-24.92%
Miscellaneous	-	-	-	0.00%
Depreciation	-	-	-	0.00%
Total Operating Expenses	**$ 70,054**	**$ 85,655**	**$ (15,601)**	**-18.21%**
Total Direct Expenses	**$ 702,009**	**$ 634,132**	**$ 67,877**	**10.70%**
Indirect Expenses	**$ (702,009)**	**$ (634,132)**	**$ (67,877)**	**10.70%**
Non-Operating Expenses	**$ -**	**$ -**	**$ -**	0.00%
Total Expenses	**$ -**	**$ -**	**$ -**	**0.00%**
Change in Assets	**$ -**	**$ -**	**$ -**	**0.00%**
Fixed Assets				
Depreciation	-	-	-	0.00%
Computer Hardware & Software	-	-	-	0.00%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	-	-	-	0.00%
	-	-	-	0.00%
Allocation of Fixed Assets	$ -	$ -	$ -	0.00%
Inc/(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	**0.00%**
Total Budget	**$ -**	**$ -**	**$ -**	**0.00%**
Total Change in Working Capital	**$ -**	**$ -**	**$ -**	**0.00%**
FTEs	**2.00**	**2.00**	**0.00**	**0.00%**

Explanation of Variances - Legal and Regulatory Affairs Program

Personnel Expenses

Salaries was over budget due to the additional compensation required to retain experienced and qualified staff.

Operating Expense

Professional Services was under budget due to performing more legal work in house.

Indirect Expenses

Indirect Expenses are expenses related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs. As a result, the variance was due to higher Legal and Regulatory Affairs expenditures being allocated.

Information Technology Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Information Technology

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ -	$ -	$ -	0.00%
Penalty Sanctions			-	0.00%
Total ReliabilityFirst Funding	**$ -**	**$ -**	**$ -**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	-	-	-	0.00%
Miscellaneous	-	-	-	0.00%
Total Funding	**$ -**	**$ -**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	$ 394,124	$ 541,390	$ (147,266)	-27.20%
Payroll Taxes	29,910	38,462	(8,552)	-22.23%
Benefits	68,545	89,227	(20,682)	-23.18%
Retirement Costs	63,029	86,074	(23,045)	-26.77%
Total Personnel Expenses	**$ 555,608**	**$ 755,153**	**$ (199,545)**	**-26.42%**
Meeting Expenses				
Meetings	$ 805	$ 720	$ 85	11.81%
Travel	12,414	11,000	1,414	12.85%
Conference Calls	43,927	38,400	5,527	14.39%
Total Meeting Expenses	**$ 57,146**	**$ 50,120**	**$ (7,026)**	**-14.02%**
Operating Expenses				
Consultants & Contracts	$ 4,884	$ 22,000	$ (17,116)	-77.80%
Office Rent	53,158	100,000	(46,842)	-46.84%
Office Costs	534,479	432,002	102,477	23.72%
Professional Services	-	-	-	0.00%
Miscellaneous	2,546	-	2,546	0.00%
Depreciation	142,586	154,583	(11,997)	-7.76%
Total Operating Expenses	**$ 737,653**	**$ 708,585**	**$ 29,068**	**4.10%**
Total Direct Expenses	**$ 1,350,407**	**$ 1,513,858**	**$ (177,503)**	**-11.73%**
Indirect Expenses	**$ (1,420,853)**	**$ (1,513,858)**	**$ 93,005**	**-6.14%**
Non-Operating Expenses	**$ 70,446**	**$ -**	**$ 70,446**	0.00%
Total Expenses	**$ -**	**$ -**	**$ (14,052)**	**0.00%**
Change in Assets	**$ -**	**$ -**	**$ 14,052**	**0.00%**
Fixed Assets				
Depreciation	(142,586)	(154,583)	11,997	-7.76%
Computer Hardware & Software CapEx	166,745	79,000	87,745	111.07%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	237,881	-	237,881	0.00%
	262,040	(75,583)	337,623	-446.69%
Allocation of Fixed Assets	$ 262,040	$ 75,583	$ 186,457	246.69%
Inc/(Dec) in Fixed Assets	**$ 524,081**	**$ -**	**$ 524,081**	**0.00%**
Total Budget	**$ 524,081**	**$ -**	**$ 510,029**	**0.00%**
Total Change in Working Capital	**$ (524,081)**	**$ -**	**$ (510,029)**	**0.00%**
FTEs	**3.75**	**5.00**	**(1.25)**	**-25.00%**

Explanation of Variances - Information Technology Program

Personnel Expenses

Personnel expenses were under budget due to a vacant position.

Operating Expense

Consultants & Contracts was under budget due to utilizing the tenant improvement allowance received for the office move to implement new software and hardware upgrades for the new office infrastructure, instead of using dollars budgeted for the implementation of anticipated infrastructure upgrades at the former office.

Office Rent was under budget due to the three months of free rent and the lower monthly rate that were negotiated for the offsite data center.

Office Costs was over budget due to the purchase of the new laptops.

Non-Operating Expenses

The variance in Non-Operating expenses was due to the losses recorded for the fixed assets that were disposed of as a result of the office move.

Fixed Assets

Computer Hardware & Software was over budget as a result of the hardware purchases made for the new office.

The variance in Leasehold Improvements was a result of the improvements made to the new office.

Human Resources Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Human Resources

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ -	$ -	$ -	0.00%
Penalty Sanctions			-	0.00%
Total ReliabilityFirst Funding	**$ -**	**$ -**	**$ -**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	-	-	-	0.00%
Miscellaneous	-	-	-	0.00%
Total Funding	**$ -**	**$ -**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	$ 267,288	$ 250,049	$ 17,239	6.89%
Payroll Taxes	21,337	18,989	2,348	12.37%
Benefits	112,022	103,512	8,510	8.22%
Retirement Costs	92,527	46,682	45,845	98.21%
Total Personnel Expenses	**$ 493,174**	**$ 419,232**	**$ 73,942**	**17.64%**
Meeting Expenses				
Meetings	$ 10,623	$ 17,030	$ (6,407)	-37.62%
Travel	6,359	9,000	(2,641)	-29.34%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 16,982**	**$ 26,030**	**$ (9,048)**	**-34.76%**
Operating Expenses				
Consultants & Contracts	$ 95,201	$ 10,000	$ 85,201	852.01%
Office Rent	-	-	-	0.00%
Office Costs	8,481	4,428	4,053	91.53%
Professional Services	34,742	34,832	(90)	-0.26%
Miscellaneous	21,147	18,910	2,237	11.83%
Depreciation	799	799	-	0.00%
Total Operating Expenses	**$ 160,370**	**$ 68,969**	**$ 91,401**	**132.52%**
Total Direct Expenses	**$ 670,526**	**$ 514,231**	**$ 156,295**	**30.39%**
Indirect Expenses	**$ (670,526)**	**$ (514,231)**	**$ (156,295)**	**30.39%**
Non-Operating Expenses	**$ -**	**$ -**	**$ -**	0.00%
Total Expenses	**$ -**	**$ -**	**$ -**	**0.00%**
Change in Assets	**$ -**	**$ -**	**$ -**	**0.00%**
Fixed Assets				
Depreciation	(799)	(799)	-	0.00%
Computer Hardware & Software	-	-	-	0.00%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	-	-	-	0.00%
	(799)	(799)	-	0.00%
Allocation of Fixed Assets	$ (799)	$ 799	$ (1,598)	-200.00%
Inc/(Dec) in Fixed Assets	**$ (1,598)**	**$ -**	**$ (1,598)**	**0.00%**
Total Budget	**$ (1,598)**	**$ -**	**$ (1,598)**	**0.00%**
Total Change in Working Capital	**$ 1,598**	**$ -**	**$ 1,598**	**0.00%**
FTEs	**3.08**	**3.00**	**0.08**	**2.67%**

Explanation of Variances - Human Resources Program

Personnel Expenses

Retirement Costs was over budget due to the administrative fees relating to the management of the company's retirement accounts.

Operating Expenses

Consultants & Contracts was over budget due to recruitment fees, executive coaching services, and services rendered for the 457 plans.

Indirect Expenses

Indirect Expenses are expenses related to the Administrative Services programs that have been allocated proportionately based on FTE count to the direct programs. As a result, the variance was due to higher Human Resources expenditures being allocated.

Finance and Accounting Program

Statement of Activities, Fixed Assets and Change in Working Capital
January 1, 2014 - December 31, 2014
Finance and Accounting

	2014 Actual	2014 Budget	2014 Variance Over(Under)	% Variance
Funding				
ReliabilityFirst Funding				
ERO Assessments	$ -	$ -	$ -	0.00%
Penalty Sanctions	-	-	-	0.00%
Total ReliabilityFirst Funding	**$ -**	**$ -**	**$ -**	**0.00%**
Membership Dues	$ -	$ -	$ -	0.00%
Federal Grants	-	-	-	0.00%
Services & Software	-	-	-	0.00%
Workshops	-	-	-	0.00%
Investment	-	-	-	0.00%
Miscellaneous	-	-	-	0.00%
Total Funding	**$ -**	**$ -**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	$ 137,388	$ 128,182	$ 9,206	7.18%
Payroll Taxes	10,532	10,136	396	3.91%
Benefits	18,748	23,850	(5,102)	-21.39%
Retirement Costs	21,998	20,461	1,537	7.51%
Total Personnel Expenses	**$ 188,666**	**$ 182,629**	**$ 6,037**	**3.31%**
Meeting Expenses				
Meetings	$ 45	$ -	$ 45	0.00%
Travel	3,791	6,000	(2,209)	-36.82%
Conference Calls	-	-	-	0.00%
Total Meeting Expenses	**$ 3,836**	**$ 6,000**	**$ (2,164)**	**-36.07%**
Operating Expenses				
Consultants & Contracts	$ -	$ -	$ -	0.00%
Office Rent	-	-	-	0.00%
Office Costs	4,635	16,103	(11,468)	-71.22%
Professional Services	51,785	43,500	8,285	19.05%
Miscellaneous	-	-	-	0.00%
Depreciation	1,797	1,797	-	0.00%
Total Operating Expenses	**$ 58,217**	**$ 61,400**	**$ (3,183)**	**-5.18%**
Total Direct Expenses	**$ 250,719**	**$ 250,029**	**$ 690**	**0.28%**
Indirect Expenses	**$ (250,719)**	**$ (250,029)**	**$ (690)**	**0.28%**
Non-Operating Expenses	**$ -**	**$ -**	**$ -**	0.00%
Total Expenses	**$ -**	**$ -**	**$ -**	**0.00%**
Change in Assets	**$ -**	**$ -**	**$ -**	**0.00%**
Fixed Assets				
Depreciation	(1,797)	(1,797)	-	0.00%
Computer Hardware & Software	-	-	-	0.00%
Furniture & Fixtures CapEx	-	-	-	0.00%
Equipment CapEx	-	-	-	0.00%
Leasehold Improvements	-	-	-	0.00%
	(1,797)	(1,797)	-	0.00%
Allocation of Fixed Assets	$ (1,797)	$ 1,797	$ (3,594)	-200.00%
Inc/(Dec) in Fixed Assets	**$ (3,594)**	**$ -**	**$ (3,594)**	**0.00%**
Total Budget	**$ (3,594)**	**$ -**	**$ (3,594)**	**0.00%**
Total Change in Working Capital	**$ 3,594**	**$ -**	**$ 3,594**	**0.00%**
FTEs	**1.60**	**1.50**	**0.10**	**6.67%**

Explanation of Variances - Finance and Accounting Program

Personnel Expenses

Benefits was under budget due to training activities and medical benefits being less than budgeted.

Operating Expenses

Office Costs was under budget due to the delay in implementing an automated expense report system.

ReliabilityFirst Corporation

Financial Report
December 31, 2014

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McGladrey

Independent Auditor's Report

To the Board of Directors
ReliabilityFirst Corporation
Independence, Ohio

Report on the Financial Statements

We have audited the accompanying financial statements of ReliabilityFirst Corporation which comprise the statements of financial position as of December 31, 2014 and 2013, and the related statements of activities and cash flows for the years then ended and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a reasonable basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of ReliabilityFirst Corporation as of December 31, 2014 and 2013, and the changes in its net assets and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Member of the RSM International network of independent accounting, tax and consulting firms.

Other Matter

Our audits were conducted for the purpose of forming an opinion on the financial statements as a whole. The accompanying supplementary information is presented for purposes of additional analysis and is not a required part of the financial statements. Such information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the financial statements. The information has been subjected to the auditing procedures applied in the audits of the financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the financial statements or to the financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the information is fairly stated in all material respects in relation to the financial statements as a whole.

McGladrey LLP

Chicago, Illinois
April 30, 2015

ReliabilityFirst Corporation

Statements of Financial Position
December 31, 2014 and 2013

	2014	2013
Assets		
Current Assets		
Cash	**$ 2,177,381**	$ 3,455,309
Investments	**3,649,963**	3,604,721
Receivables:		
Accounts	**204,795**	164,055
Lease incentives	**-**	855,301
Prepaid expenses	**113,442**	424,736
Total current assets	**6,145,581**	8,504,122
Fixed Assets		
Furniture and equipment	**246,138**	132,793
Leasehold improvements	**1,888,108**	859,549
Computer software and hardware	**2,161,404**	2,272,671
	4,295,650	3,265,013
Less accumulated depreciation and amortization	**1,922,452**	1,956,014
	2,373,198	1,308,999
Total assets	**$ 8,518,779**	$ 9,813,121
Liabilities and Net Assets		
Current Liabilities		
Accounts payable	**$ 38,494**	$ 591,485
Accrued expenses (current portion)	**3,349,416**	3,673,974
Notes payable (current portion)	**51,795**	-
Total current liabilities	**3,439,705**	4,265,459
Long-Term Liabilities		
Accrued expenses (net of current portion)	**174,686**	228,348
Notes payable (net of current portion)	**86,336**	-
Deferred revenue	**250,000**	-
Deferred rent	**2,419,564**	855,301
	2,930,586	1,083,649
Net Assets		
Unrestricted:		
Undesignated (deficit)	**(214,012)**	1,620,880
Designated for reserve fund	**1,000,000**	1,000,000
Temporarily restricted	**1,362,500**	1,843,133
Total net assets	**2,148,488**	4,464,013
Total liabilities and net assets	**$ 8,518,779**	$ 9,813,121

See Notes to Financial Statements.

ReliabilityFirst Corporation

Statements of Activities
Years Ended December 31, 2014 and 2013

	2014	2013
Unrestricted Net Assets		
Revenues:		
Quarterly assessments	**$ 15,159,784**	$ 14,165,848
Investment gain income (loss)	**45,242**	(66,853)
Penalty sanctions released from restriction	**1,358,133**	2,979,800
Miscellaneous	**43,600**	-
	16,606,759	17,078,795
Expenses:		
Program:		
Standards	**21,143**	133,503
Compliance	**8,181,135**	8,567,222
Enforcement	**1,249,147**	-
Assessment	**1,847,628**	1,954,152
Training and education	**662,269**	646,201
Situational awareness	**189,891**	192,074
General and administrative	**2,879,768**	2,566,017
Legal and regulatory	**702,010**	592,849
Information technology	**1,207,822**	1,353,083
Human resources	**669,719**	632,410
Finance	**248,921**	308,523
	17,859,453	16,946,034
General:		
Depreciation and amortization	**425,230**	428,936
Loss (gain) on disposal of fixed assets	**154,454**	(255)
Interest expense	**2,514**	-
	582,198	428,681
	18,441,651	17,374,715
Decrease in unrestricted net assets	**(1,834,892)**	(295,920)
Temporarily Restricted Net Assets		
Penalty sanctions	**877,500**	860,000
Penalty sanctions released from restriction	**(1,358,133)**	(2,979,800)
Decrease in temporarily restricted net assets	**(480,633)**	(2,119,800)
Decrease in total net assets	**(2,315,525)**	(2,415,720)
Net assets at beginning of year	**4,464,013**	6,879,733
Net assets at end of year	**$ 2,148,488**	$ 4,464,013

See Notes to Financial Statements.

ReliabilityFirst Corporation

Statements of Cash Flows
Years Ended December 31, 2014 and 2013

	2014	2013
Cash Flows from Operating Activities		
Change in net assets	**$ (2,315,525)**	$ (2,415,720)
Adjustments to reconcile change in net assets to net cash provided by (used in) operating activities:		
Depreciation and amortization	**425,230**	428,936
Loss (gain) on disposal of fixed assets	**154,454**	(255)
Unrealized (gain) loss on investments	**(77,947)**	141,889
Realized loss on investments	**68,073**	6,309
Changes in assets and liabilities:		
Accounts receivable	**(40,740)**	727,579
Lease incentives receivable	**855,301**	(855,301)
Prepaid expenses	**311,294**	(221,431)
Accounts payable	**(552,991)**	503,848
Accrued expenses	**(378,220)**	130,751
Deferred revenue	**250,000**	-
Deferred rent	**1,564,263**	855,301
Net cash provided by (used in) operating activities	**263,192**	(698,094)
Cash Flows from Investing Activities		
Purchase of investments	**(3,689,869)**	(81,345)
Sale of investments	**3,654,501**	1,500,000
Purchases of fixed assets	**(1,646,253)**	(599,808)
Proceeds from sale of fixed assets	**2,370**	-
Net cash used in (provided by) investing activities	**(1,679,251)**	818,847
Cash Flows from Financing Activities		
Borrowing on notes payable	**159,110**	-
Payments on notes payable	**(20,979)**	-
Net cash provided by financing activities	**138,131**	-
Net (decrease) increase in cash	**(1,277,928)**	120,753
Cash at beginning of year	**3,455,309**	3,334,556
Cash at end of year	**$ 2,177,381**	$ 3,455,309
Supplemental Disclosure of Cash Flow Information		
Cash payments for interest	**$ 2,514**	$ -

See Notes to Financial Statements.

Note 1. Organization and Significant Accounting Policies

Organization: ReliabilityFirst Corporation (the Corporation) is a not-for-profit corporation whose mission is to preserve and enhance bulk power system reliability and security for the interconnected electric systems within its territory. The Corporation was approved by the North American Electric Reliability Corporation (NERC) to become one of eight Regional Entities of NERC. The Corporation conducts its activities from leased offices in Independence, Ohio.

The Corporation receives its quarterly assessments from NERC. A significant reduction in the level of this support, if this were to occur, may have a significant effect on the Corporation's operations.

The following is a summary of the Corporation's significant accounting policies which conform to accounting principles generally accepted in the United States of America (U.S. GAAP).

Use of estimates: The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Revenue recognition: The Corporation currently derives its revenues primarily from quarterly assessments. Revenues from such assessments are recognized as unrestricted revenues at the time services are performed and the cost of these services is recognized when incurred. Penalty sanctions are recognized after the entire appeals process has been exhausted and a Federal Electric Regulatory Commission (FERC) order has been issued and is non-appealable. Penalty sanctions received on or prior to June 30 of each year shall be applied as a general offset to budget requirements for the subsequent fiscal year. Penalty sanctions received after June 30 of each year shall be applied as a general offset to budget requirements for the next subsequent fiscal year.

Cash: The Corporation maintains its cash in non-interest-bearing bank deposit accounts. Management believes it is not exposed to any significant credit risk on cash.

Receivables: Accounts receivable are carried at actual billed amounts relating to penalty sanctions and subcontractor receivables. There was no allowance for doubtful accounts recorded in 2014 or 2013. During 2013, the Corporation recorded a receivable of $855,301 from its new landlord relating to lease incentives provided to reimburse leasehold improvements and a termination penalty on an existing lease, which related to 2013. This was collected in full during 2014.

Investments: Investments are carried at fair value. The fair values of marketable debt securities are based on quoted market prices. Realized investment gains and losses represent the difference between the proceeds on sales of investments and their carrying value. Investment income includes interest, dividends and both realized and unrealized gains and losses. All realized and unrealized gains and losses on investments are reported as increases or decreases, respectively, to unrestricted net assets.

The Corporation invests in fixed income corporate bonds. Such investments are exposed to various risks such as interest rate, market and credit. Due to the level of risk associated with such investments and the level of uncertainty related to changes in the value of such investments, it is at least reasonably possible that changes in risks in the near term would materially affect investment balances and the amounts reported in the financial statements.

Prepaid expenses: Prepaid expenses consist of expenses paid for in advance that will be recognized within a future operating cycle.

Note 1. Organization and Significant Accounting Policies (Continued)

Fixed assets: Fixed assets are stated at cost. Depreciation is computed on the straight-line method over the estimated useful lives (generally 3 to 7 years) of the depreciable assets. Amortization for the leasehold improvements is computed on the lesser of the useful life or the lease term.

Accrued expenses: Accrued expenses consist primarily of salaries and related payroll expenses incurred in the current fiscal year but not paid until after year end. An amount of $174,686 has been classified as a long-term liability as it is expected this amount will be paid after December 31, 2015.

Deferred revenue: Amounts received by the Corporation prior to when the revenue is earned are recorded as deferred revenue.

Income taxes: The Corporation is exempt from federal income taxes under Section 501(c)(3) of the Internal Revenue Code and applicable state law, except for taxes pertaining to unrelated business income, if any.

In accordance with the accounting standard on accounting for uncertainty in income taxes, the Corporation addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Corporation may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by taxing authorities, based on the technical merits of the position. Examples of tax positions include the tax-exempt status of the Corporation and various positions related to the potential sources of unrelated business taxable income (UBIT). The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement. There were no unrecognized tax benefits identified or recorded as liabilities during the periods covered by these financial statements.

The Corporation currently files the form 990 in the U.S. federal jurisdiction. The Corporation is generally no longer subject to examination by the Internal Revenue Service for years before 2011.

Net assets: Of the unrestricted net asset balance, $1,000,000 has been designated by the Board of Directors for its operating reserve fund at December 31, 2014 and 2013. During 2014, the Corporation's Board of Directors decided to reduce the operating reserve to $750,000 in 2015.

Temporarily restricted net assets result from the receipt of penalty sanctions which are restricted based on timing conditions as described in the Corporation's revenue recognition policy. Penalty monies are governed by a restriction by NERC as to when the funds can be used. Temporarily restricted net assets at December 31, 2014 and 2013, were $1,362,500 and $1,843,133, respectively.

Subsequent events: The Corporation has evaluated subsequent events for potential recognition and/or disclosure through the date these financial statements were available to be issued.

Note 2. Investments and Fair Value Measurements

The Corporation previously maintained an investment portfolio which consisted of fixed income Class A mutual funds. In 2014, the Corporation transferred its investments to a new investment firm, and has invested in U.S. Treasury obligations, U.S. Government agency securities, and corporate bonds.

As described in Note 1, the Corporation records its investments at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Financial Accounting Standards Board's (FASB) authoritative guidance on fair value measurements establishes a framework for measuring fair value, and expands disclosure about fair value measurements. This guidance enables the reader of the financial statements to assess the inputs used to develop those measurements by establishing a hierarchy for ranking the quality and reliability of the information used to determine fair values. Under this guidance, assets and liabilities carried at fair value must be classified and disclosed in one of the following three categories:

- Level 1: Valuations for assets and liabilities traded in active exchange markets, such as the New York Stock Exchange. Level 1 also includes U.S. Treasury and federal agency securities and federal agency mortgage-backed securities, which are traded by dealers or brokers in active markets. Valuations are obtained from readily available pricing sources for market transactions involving identical assets or liabilities.
- Level 2: Valuations for assets and liabilities traded in less active dealer or broker markets. Valuations are obtained from third-party pricing services for identical or similar assets or liabilities.
- Level 3: Valuations for assets and liabilities that are derived from other valuation methodologies, including option pricing models, discounted cash flow models and similar techniques, and not based on market exchange, dealer, or broker-traded transactions. Level 3 valuations incorporate certain assumptions and projections in determining the fair value assigned to such assets or liabilities.

In determining the appropriate levels, the Corporation performs a detailed analysis of the assets and liabilities that are measured and reported on a fair value basis. At each reporting period, all assets and liabilities for which the fair value measurement is based on significant unobservable inputs would be classified as Level 3.

The Corporation assesses the levels at each measurement date, and transfers between levels are recognized on the date of the actual event or change in the circumstances that caused the transfer in accordance with the Corporation's accounting policy regarding the recognition of the transfer between levels of the fair value hierarchy. For the years ended December 31, 2014 and 2013, there were no such transfers.

Note 2. Investments and Fair Value Measurements (Continued)

The following tables present the Corporation's fair value hierarchy for its investments as of December 31, 2014 and 2013:

	December 31, 2014			
	Level 1	Level 2	Level 3	Total
U.S. Government securities	$ 858,648	$ -	$ -	$ 858,648
Corporate bonds	-	2,682,335	-	2,682,335
	$ 858,648	$ 2,682,335	$ -	3,540,983
Cash and cash equivalents				108,980
				$ 3,649,963

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Fixed Income Class A Mutual Funds	$ 3,604,721	$ -	$ -	$ 3,604,721

The composition of investment income (loss) is as follows at December 31:

	2014	2013
Interest/dividends	$ 74,977	$ 81,345
Realized loss	(107,682)	(6,309)
Unrealized gain (loss)	77,947	(141,889)
	$ 45,242	$ (66,853)

Note 3. Line of Credit

The Corporation has a $1,000,000 line of credit with an expiration date of July 14, 2015. The line is collateralized by substantially all assets of the Corporation and interest is charged at LIBOR plus 4.199 percent. The Corporation did not make any drawdowns on the line during the year and had no outstanding balance as of December 31, 2014 or 2013. The Corporation intends to renew the line when it becomes due on July 14, 2015.

Note 4. Notes Payable

The Corporation entered into a note payable with a bank on July 14, 2014 for $159,110 to fund the purchase of laptop computers. The note bears an interest rate of 3.950 percent per annum, until paid in full and requires the Corporation to pay the loan in 36 payments of $4,698.51 (including principal and interest). The note is collateralized by the laptops that were purchased.

Maturities of notes payable are as follows as of December 31:

2015	$ 51,795
2016	53,899
2017	32,437
	$ 138,131

Note 5. Operating Leases

On July 16, 2013, the Corporation provided written notice exercising its early termination right for its lease with Bath Springside, Ltd. (Bath). As a result, the Bath lease terminated on December 31, 2014 and the Corporation incurred a lease termination penalty of $200,000, which was reimbursed by its new landlord, Investors Warranty of America, Inc. (Investors), an unrelated third party. The penalty was recorded in accounts payable at December 31, 2013, and was paid by the Corporation in 2014.

On June 14, 2013, the Corporation signed a 13 year lease with Investors. The Corporation took occupancy of the new office effective March 1, 2014. According to the Investors lease, the Corporation was provided with a $1,854,956 tenant improvement allowance for leasehold improvements and other soft costs.

The above reimbursement of the Bath lease termination penalty and the leasehold improvement allowance totaling $2,054,956 was received from Investors in 2014. This amount is being amortized over the life of the lease against rent expense, starting on the commencement date of the new lease (March 1, 2014).

Rental expense for operating leases amounted to $692,003 and $508,704 for the years ended December 31, 2014 and 2013, respectively. Rent expense in 2014 and 2013 includes $72,537 and $32,114, respectively, in accelerated straight-line amortization of the previous deferred rent liability due to the early termination of the Bath lease. The deferred rent liability was $2,419,564 and $855,301 as of December 31, 2014 and 2013, respectively.

The future minimum lease payments relating to the new lease on a straight-line basis are as follows:

2015	$ 595,603
2016	595,603
2017	595,603
2018	595,603
2019	595,603
Thereafter	4,268,490
	$ 7,246,505

Note 6. Employee Retirement Plan

The Corporation has a salary deferral plan under Section 401(k) of the Internal Revenue Code. All employees are eligible for 100 percent match of their first 6 percent of voluntary salary deferral savings and the 3 percent Safe Harbor provision of the plan. Employees who have at least 1,000 hours during the year are eligible for a certain percentage discretionary provision of the plan (7 percent in 2014 and 2013). Therefore, under this plan, the Corporation provided for a potential maximum contribution of up to 16 percent of employees' eligible compensation in 2014 and 2013. The Corporation's contributions to the plan for 2014 and 2013 were approximately $1,580,000 and $1,469,000, respectively.

Note 7. Grant from City of Independence, Ohio

In connection with the Corporation's office move during 2014, the City of Independence (City) awarded a $350,000 grant to the Corporation. The grant agreement provides for the Corporation to meet minimum annual payroll tax requirements as well as a requirement that the Corporation will not re-locate outside of the City during the next 12 years. If the re-location requirement is not met by the Corporation, the full $350,000 will be required to be returned to the City upon default. The Corporation received $250,000 of this grant in 2014, and recorded this amount in deferred revenue due to the requirements of the grant not being met as of December 31, 2014. The agreement allows for the remaining $100,000 to be paid during 2015 (but no later than 2016), which will also be reflected in deferred revenue when it is received.

ReliabilityFirst Corporation

Schedule of Program Expenses
Year Ended December 31, 2014

	Standards	Compliance	Enforcement	Assessment	Training and Education	Situational Awareness	General and Administrative	Legal and Regulatory	Information Technology	Human Resources	Finance	Total
Personnel Expenses												
Salaries	$ 8,854	$ 5,501,147	$ 840,569	$ 1,208,251	$ 419,181	$ 111,642	$ 1,118,071	$ 465,904	$ 394,124	$ 267,288	$ 137,388	$ 10,472,419
Payroll taxes	1,876	337,941	71,142	79,143	29,786	6,697	48,857	22,426	29,910	21,337	10,534	659,649
Employee benefits	2,688	702,131	146,690	121,429	56,625	10,766	66,377	31,179	68,545	112,022	18,749	1,337,201
Savings and retirement	4,856	770,217	125,798	196,167	66,761	18,791	152,848	67,287	63,029	92,527	21,998	1,580,279
Total personnel expenses	18,274	7,311,436	1,184,199	1,604,990	572,353	147,896	1,386,153	586,796	555,608	493,174	188,669	14,049,548
Meeting Expenses												
Meetings	-	10,853	3,549	12,487	83,110	4,823	64,513	167	805	10,623	45	190,975
Travel	2,114	437,446	46,823	89,620	6,791	26,087	50,311	44,992	12,414	6,359	3,790	726,747
Conference calls	-	-	-	-	-	-	-	-	43,927	-	-	43,927
Total meeting expenses	2,114	448,299	50,372	102,107	89,901	30,910	114,824	45,159	57,146	16,982	3,835	961,649
Operating Expenses												
Rent and improvements	-	-	-	-	-	-	699,024	-	53,158	-	-	752,182
Contracts	-	157,301	3,500	80,766	-	5,000	53,608	5,000	4,884	95,201	-	405,260
Office costs	575	57,277	10,956	8,228	15	2,590	26,973	16,054	145,012	5,426	1,374	274,480
Professional services	-	-	-	-	-	-	427,060	48,801	-	34,742	51,785	562,388
Computer purchase and maintenance	-	206,437	-	51,537	-	3,428	38,873	200	387,351	3,055	3,258	694,139
Furniture and equipment	-	-	-	-	-	-	76,518	-	2,117	-	-	78,635
Office relocation	-	-	-	-	-	-	41,431	-	-	-	-	41,431
Miscellaneous	180	385	120	-	-	67	15,304	-	2,546	21,139	-	39,741
Total operating expenses	755	421,400	14,576	140,531	15	11,085	1,378,791	70,055	595,068	159,563	56,417	2,848,256
Subtotal	$ 21,143	$ 8,181,135	$ 1,249,147	$ 1,847,628	$ 662,269	$ 189,891	$ 2,879,768	$ 702,010	$ 1,207,822	$ 669,719	$ 248,921	17,859,453
Depreciation and amortization												425,230
Loss on disposal of assets												154,454
Interest expense												2,514
Total expenses												$ 18,441,651

ReliabilityFirst Corporation

Schedule of Program Expenses
Year Ended December 31, 2013

	Standards	Compliance	Assessment	Training and Education	Situational Awareness	General and Administrative	Legal and Regulatory	Information Technology	Human Resources	Finance	Total
Personnel Expenses											
Salaries	$ 85,293	$ 5,456,087	$ 1,308,756	$ 419,851	$ 122,270	$ 1,209,523	$ 374,928	$ 592,533	$ 250,700	$ 187,490	$ 10,007,431
Payroll taxes	7,190	355,198	79,803	28,288	6,222	41,727	20,144	41,223	18,791	13,244	611,830
Employee benefits	10,677	751,014	119,349	54,888	5,141	67,553	29,042	101,658	134,902	31,776	1,306,000
Savings and retirement	16,969	801,891	201,906	63,056	18,418	157,352	60,471	87,574	60,524	23,833	1,491,994
Total personnel expenses	120,129	7,364,190	1,709,814	566,083	152,051	1,476,155	484,585	822,988	464,917	256,343	13,417,255
Meeting Expenses											
Meetings	-	12,964	19,252	74,751	9,638	35,702	718	1,223	19,144	-	173,392
Travel	11,216	490,599	94,243	5,367	25,013	71,650	43,800	11,866	7,778	4,354	765,886
Conference calls	-	-	-	-	-	-	-	38,097	-	-	38,097
Total meeting expenses	11,216	503,563	113,495	80,118	34,651	107,352	44,518	51,186	26,922	4,354	977,375
Operating Expenses											
Rent and improvements	-	-	-	-	-	560,012	-	-	-	-	560,012
Contracts	-	409,643	79,557	-	-	32,750	-	9,031	78,507	-	609,488
Office costs	2,037	84,876	11,266	-	2,571	30,601	13,643	317,073	3,143	1,917	467,127
Professional services	-	15,000	-	-	-	306,661	50,095	-	37,250	42,659	451,665
Computer purchase and maintenance	-	188,691	39,961	-	1,920	39,603	-	151,166	5,173	3,250	429,764
Furniture and equipment	-	-	-	-	-	2,647	-	-	-	-	2,647
Miscellaneous	121	1,259	59	-	881	10,236	8	1,639	16,498	-	30,701
Total operating expenses	2,158	699,469	130,843	-	5,372	982,510	63,746	478,909	140,571	47,826	2,551,404
Subtotal	$ 133,503	$ 8,567,222	$ 1,954,152	$ 646,201	$ 192,074	$ 2,566,017	$ 592,849	$ 1,353,083	$ 632,410	$ 308,523	16,946,034
Depreciation and amortization											428,936
Loss on disposal of assets											(255)
Total expenses											$ 17,374,715

ATTACHMENT 6

2014 ACTUAL COST-TO-BUDGET COMPARISON

AND

2014 AUDITED FINANCIAL REPORT

FOR

SERC RELIABILITY CORPORATION

SERC Reliability Corporation
3701 Arco Corporate Drive, Suite 300
Charlotte, NC 28273
704.357.7372 | Fax 704.357.7914 | www.serc1.org

May 5, 2015

Mike Walker
Chief Financial Officer
North American Electric Reliability Corporation

SERC 2014 Budget vs. Actual Variance Analysis

Enclosed is SERC's response to your request for information on variances between the 2014 SERC budget and year-end financials.

Overall, SERC under ran 2014 budgeted revenues by $43,859 and under spent its 2014 budgeted expenses of $16,585,941 by $1,181,316. The net impact was a $1,137,457 positive variance on SERC's cash position for the year.

During 2014, SERC conducted 54 audits and spot checks including 6 on-site and 22 off-site operations and planning audits, 6 on-site and 17 off-site CIP audits, and 3 on-site CIP spot checks. There were no audits of multi-regional Registered Entities. SERC adjusted the planned audits and spot checks pursuant to supplemental guidance provided by NERC and FERC. SERC received 141 new potential violations and closed 253 enforcement actions addressing possible violations identified during the period from 2010 through 2014. In addition, SERC completed all budgeted reliability assessments for the year.

There are several mitigating circumstances, as explained below:

- Workshop fees are lower than budget due to SERC hosted most meetings in house or at a member's facilities, resulting in a savings in costs, and therefore an offsetting decrease in revenue allowing SERC to charge a reduced attendance fee, from when the budget was developed. Additionally, due to a change in format, SERC hosted less meetings than originally budgeted.
- Miscellaneous income is higher than budget due to contractual repayments of employee benefits, and proceeds from the sale of the old office furniture.
- During 2014, total personnel costs were lower than budget primarily due to SERC was not fully staffed by 11.82 FTEs. As an offset, SERC used contractors in lieu of FTEs, causing an over run in Consultants and Contractors.
- SERC moved into a new office space in 2014 with a large meeting space. Most meetings were held in-house or at a member's facilities, substantially reducing the hotel hosting costs and decreasing Meeting and Travel Expense.

- SERC signed a new lease, with a commencement date of April 1, 2014, which included ten months of free rent. GAAP requires rent to be recorded on a straight line basis, accounting for the free rent. SERC did not incur actual rent expense for the new office space. However, due to accounting principles, an entry for the new space was recorded on a straight line basis, causing rent expense to be higher than budget. An off-setting entry was recorded as a liability on the balance sheet.
- SERC engaged an architect and a construction manager to assist with the construction, furniture selection, and coordination of the relocation of SERC's offices; and additional work was performed on various IT projects for compliance and assessments, causing an unplanned over run in Consultants and Contractors.
- SERC purchased office furniture and equipment to furnish the new office space, causing the over run in Office Costs.

SERC has no non-statutory activity, and therefore no statutory funding was used for non-statutory activities.

All personnel costs for the other administrative functions, including Information Technology, Legal, Finance, and Human Resources, are recorded within General and Administrative to protect the confidentiality of individual compensation information of employees in these programs.

SERC allocates indirect or administrative expenses and capital expenditures to the statutory programs based upon the ratio of FTEs in those program areas to total statutory program FTEs. The variances associated with this allocation are the result of the differences in the actual versus budgeted ratio of FTEs and the actual versus budgeted spend in the administrative cost centers.

SERC performs the Compliance Enforcement Activities for FRCC and SPP. The regional entity reimburses SERC for the actual costs incurred, including an overhead calculation. These costs have been recorded separately on the Compliance Enforcement Activity Statement of Activities.

Detailed descriptions of budget to actual variances are provided in the attached file. If you have any questions, please feel free to call or email me.

Yours truly,

Jennifer Kelly

cc: R. Scott Henry, President/CEO
Gary Taylor, Vice President/COO

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014			
Total Statutory	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**
Funding			
ERO Funding			
Assessments	13,734,499	13,734,499	-
Penalty Sanctions	2,054,500	2,054,500	-
Total ERO Funding	**$15,788,999**	**$ 15,788,999**	**$ -**
Federal Grants	-	-	-
Membership Fees	-	-	-
Testing	-	-	-
Services & Software	-	-	-
Workshop Fees	185,280	267,605	(82,325)
Interest	2,054	10,000	(7,946)
Miscellaneous	354,912	308,500	46,412
Total Funding (A)	**$16,331,245**	**$ 16,375,104**	**$ (43,859)**
Expenses			
Personnel Expenses			
Salaries	8,694,787	10,187,444	(1,492,657)
Payroll Taxes	580,037	611,246	(31,209)
Employee Benefits	876,645	941,806	(65,161)
Savings & Retirement	1,048,875	1,394,422	(345,547)
Total Personnel Expenses	**11,200,344**	**13,134,918**	**(1,934,574)**
Meeting Expenses			
Meetings	256,954	317,195	(60,241)
Travel	480,897	605,484	(124,587)
Conference Calls	39,099	48,000	(8,901)
Total Meeting Expenses	**776,950**	**970,679**	**(193,729)**
Operating Expenses			
Consultants & Contracts	1,449,604	1,229,030	220,574
Rent & Improvements	798,011	419,861	378,150
Office Costs	750,881	477,400	273,481
Professional Services	131,166	120,400	10,766
Miscellaneous	14,537	-	14,537
Depreciation	277,062	218,653	58,409
Total Operating Expenses	**3,421,261**	**2,465,344**	**955,917**
Indirect Expenses	-	-	-
Other Non-Operating Expenses	**6,070**	**15,000**	**(8,930)**
Total Expenses (B)	**15,404,625**	**16,585,941**	**(1,181,316)**
Change in Assets (A - B)	**926,620**	**(210,837)**	**1,137,457**
Fixed Assets			
Depreciation	(277,062)	(218,653)	(58,409)
Computer & Software CapEx	227,998	460,000	(232,002)
Furniture & Fixtures CapEx	-	-	-
Equipment CapEx	-	50,000	(50,000)
Leasehold Improvements	187,453	-	187,453
Incr(Dec) in Fixed Assets	**(138,389)**	**(291,347)**	**152,958**
Allocation of Fixed Assets	-	-	-
Total Inc(Dec) in Fixed Assets (C)	**(138,389)**	**(291,347)**	**152,958**
TOTAL BUDGET (B - C)	**15,543,014**	**16,877,288**	**(1,334,274)**
Change in Working Capital (A-B+C)	**788,231**	**(502,184)**	**1,290,415**
FTE's	**67.38**	**79.20**	**(11.82)**

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
RELIABILITY STANDARDS	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	466,802	466,802	-	0.00%
Penalty Sanctions	79,938	79,938	-	0.00%
Total ERO Funding	**$ 546,740**	**$ 546,740**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	200	-	200	
Total Funding (A)	546,940	546,740	200	0.04%
Expenses				
Personnel Expenses				
Salaries	78,760	221,774	(143,014)	-64.49%
Payroll Taxes	5,844	13,306	(7,462)	-56.08%
Employee Benefits	23,878	24,786	(908)	-3.66%
Savings & Retirement	12,893	31,259	(18,366)	-58.75%
Total Personnel Expenses	121,375	291,125	(169,750)	-58.31%
Meeting Expenses				
Meetings	300	-	300	
Travel	1,395	11,696	(10,301)	-88.07%
Conference Calls	-	-	-	
Total Meeting Expenses	1,695	11,696	(10,001)	-85.51%
Operating Expenses				
Consultants & Contracts	16,654	-	16,654	
Rent & Improvements	-	-	-	
Office Costs	-	100	(100)	-100.00%
Professional Services	-	-	-	
Miscellaneous	300	-	300	
Depreciation	-	-	-	
Total Operating Expenses	16,954	100	16,854	16854.00%
Indirect Expenses	336,959	232,483	104,476	44.94%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	476,983	535,404	(58,421)	-10.91%
Change in Assets (A - B)	69,957	11,336	58,621	517.12%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	6,812	11,336	(4,524)	-39.91%
Total Inc(Dec) in Fixed Assets (C)	6,812	11,336	(4,524)	-39.91%
TOTAL BUDGET (B + C)	**483,795**	**546,740**	**(53,897)**	**-9.86%**
Change in Working Capital (A-B-C)	**63,145**	**-**	**54,097**	
FTE's	**1.15**	**2.31**	**(1.16)**	**-50.22%**

Reliability Standards
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Personnel Expenses (Actual $169,750 under budget)

- Due to turnover and the length of time to fill vacant positions, SERC is under budget in personnel expenses. SERC budgeted 2.31 FTEs in the Standards program during 2014. SERC finished 2014 with 1.15 FTEs in the Standards program, a difference of 1.16 FTEs.
- SERC reclassified 0.2 FTEs of an existing budgeted position from Reliability Standards into General and Administrative, causing a decrease in personnel expense.

Travel Expense (Actual $10,301 under budget)

- Due to the open positions, SERC has had less staff travel. Additionally, SERC has put a greater emphasis on hosting meetings in the Charlotte office, causing a decrease in travel expenses.

Consultants and Contracts Expense (Actual $16,654 over budget)

- To assist with short-term needs, SERC used consultants in lieu of hiring FTEs, causing SERC to be over budget.

Indirect Expenses (Actual $104,476 over budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
COMPLIANCE OPERATIONS, ENFORCEMENT and ORGANIZATION REGISTRATION	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	10,372,696	10,372,696	-	0.00%
Penalty Sanctions	1,470,713	1,470,713	-	0.00%
Total ERO Funding	**$ 11,843,409**	**$11,843,409**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	840	-	840	
Total Funding (A)	11,844,249	11,843,409	840	0.01%
Expenses				
Personnel Expenses				
Salaries	3,997,328	5,201,393	(1,204,065)	-23.15%
Payroll Taxes	279,538	313,476	(33,938)	-10.83%
Employee Benefits	396,358	523,055	(126,697)	-24.22%
Savings & Retirement	554,549	716,689	(162,140)	-22.62%
Total Personnel Expenses	5,227,773	6,754,613	(1,526,840)	-22.60%
Meeting Expenses				
Meetings	16,348	14,010	2,338	16.69%
Travel	231,063	319,556	(88,493)	-27.69%
Conference Calls	-	-	-	
Total Meeting Expenses	247,411	333,566	(86,155)	-25.83%
Operating Expenses				
Consultants & Contracts	293,359	245,000	48,359	19.74%
Rent & Improvements	-	-	-	
Office Costs	12,930	13,857	(927)	-6.69%
Professional Services	13,467	15,000	(1,533)	-10.22%
Miscellaneous	571	-	571	
Depreciation	-	-	-	
Total Operating Expenses	320,327	273,857	46,470	16.97%
Indirect Expenses	4,664,056	4,272,813	391,243	9.16%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	10,459,567	11,634,849	(1,175,282)	-10.10%
Change in Assets (A - B)	1,384,682	208,560	1,176,122	563.93%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	94,363	208,560	(114,197)	-54.75%
Total Inc(Dec) in Fixed Assets (C)	94,363	208,560	(114,197)	-54.75%
TOTAL BUDGET (B + C)	**10,553,930**	**11,843,409**	**(1,061,085)**	**-8.96%**
Change in Working Capital (A-B-C)	**1,290,319**	**-**	**1,061,925**	
FTE's	**32.00**	**42.50**	**(10.50)**	**-24.71%**

Compliance Operations, Enforcement and Organization Registration
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Personnel Expenses (Actual $1,526,840 under budget)

- Due to turnover and the length of time to fill vacant positions, SERC is under budget in personnel expenses. SERC budgeted 42.50 FTEs in the Compliance program during 2014. SERC finished 2014 with 32.00 FTEs in the Compliance program, a difference of 10.50 FTEs. SERC used contractors to assist in completing the work.
- SERC reclassified 2.0 FTEs existing budgeted positions from Compliance into General and Administrative, causing a decrease in personnel expense.

Travel Expense (Actual $88,493 under budget)

- Due to the open positions, SERC has had less staff travel. Additionally, SERC has put a greater emphasis on hosting meetings in the Charlotte office, causing a decrease in travel expenses.
- SERC staff traveled to fewer audits due to a change in the process to conduct off-site audits.

Consultants and Contracts Expense (Actual $48,359 over budget)

- In addition to the use of contractors due to vacant positions, as described above, SERC developed tools for required enhancements for compliance monitoring and data collection methods to support the transition to CIP version 5 and CIP self certification, causing an unplanned over run.

Indirect Expenses (Actual $391,243 over budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
COMPLIANCE ENFORCEMENT ACTIVITY	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	-	-	-	
Penalty Sanctions	-	-	-	
Total ERO Funding	$ -	$ -	$ -	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	30,625	32,000	(1,375)	-4.30%
Total Funding (A)	30,625	32,000	(1,375)	-4.30%
Expenses				
Personnel Expenses				
Salaries	26,852	23,214	3,638	15.67%
Payroll Taxes	-	-	-	
Employee Benefits	-	-	-	
Savings & Retirement	-	-	-	
Total Personnel Expenses	26,852	23,214	3,638	15.67%
Meeting Expenses				
Meetings	-	-	-	
Travel	-	4,306	(4,306)	-100.00%
Conference Calls	-	-	-	
Total Meeting Expenses	-	4,306	(4,306)	-100.00%
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	-	-	-	
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	-	-	-	
Indirect Expenses	3,773	4,480	(707)	-15.78%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	30,625	32,000	(1,375)	-4.30%
Change in Assets (A - B)	-	-	-	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	**30,625**	**32,000**	**(1,375)**	**-4.30%**
Change in Working Capital (A-B-C)	-	-	-	
FTE's	-	-	-	

Compliance Enforcement Activity
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

There are no variances requiring explanation. The income and expenses recorded relates to the cross regional monitoring activities for FRCC and SPP. The regional entity reimburses SERC for actual costs incurred. The 2014 Budget included $32,000 related to activities for FRCC and SPP.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	1,938,061	1,938,061	-	0.00%
Penalty Sanctions	262,998	262,998	-	0.00%
Total ERO Funding	**$2,201,059**	**$ 2,201,059**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	756	-	756	
Total Funding (A)	2,201,815	2,201,059	756	0.03%
Expenses				
Personnel Expenses				
Salaries	709,479	818,555	(109,076)	-13.33%
Payroll Taxes	58,419	49,113	9,306	18.95%
Employee Benefits	135,871	95,406	40,465	42.41%
Savings & Retirement	82,196	115,313	(33,117)	-28.72%
Total Personnel Expenses	985,965	1,078,387	(92,422)	-8.57%
Meeting Expenses				
Meetings	29,260	39,990	(10,730)	-26.83%
Travel	62,154	45,487	16,667	36.64%
Conference Calls	-	-	-	
Total Meeting Expenses	91,414	85,477	5,937	6.95%
Operating Expenses				
Consultants & Contracts	189,900	232,500	(42,600)	-18.32%
Rent & Improvements	-	-	-	
Office Costs	2,711	2,518	193	7.66%
Professional Services	81	-	81	
Miscellaneous	1,286	-	1,286	
Depreciation	-	-	-	
Total Operating Expenses	193,978	235,018	(41,040)	-17.46%
Indirect Expenses	908,768	764,881	143,887	18.81%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	2,180,125	2,163,763	16,362	0.76%
Change in Assets (A - B)	21,690	37,296	(15,606)	-41.84%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	18,371	37,296	(18,925)	-50.74%
Total Inc(Dec) in Fixed Assets (C)	18,371	37,296	(18,925)	-50.74%
TOTAL BUDGET (B + C)	**2,198,496**	**2,201,059**	**35,287**	**1.60%**
Change in Working Capital (A-B-C)	**3,319**	**-**	**(34,531)**	
FTE's	**6.23**	**7.60**	**(1.37)**	**-18.03%**

Reliability Assessments and Performance Analysis
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Personnel Expenses (Actual $92,422 under budget)

- Due to turnover and the length of time to fill vacant positions, SERC is under budget in personnel expenses. SERC budgeted 7.60 FTEs in the Assessments program during 2014. SERC finished 2014 with 6.23 FTEs in the Assessments program, a difference of 1.37 FTEs.
- SERC reclassified 0.2 FTEs of an existing budgeted position from Reliability Assessments into General and Administrative, causing a decrease in personnel expense.
- Payroll taxes and benefits expense are higher than budget due to unbudgeted relocation costs that were incurred in filling the vacant positions.

Meeting Expense (Actual $10,730 under budget)

- The under run in meeting expenses is due to a greater emphasis on hosting meetings at SERC's office and member facilities.

Travel Expense (Actual $16,667 over budget)

- Due to staff transitions, more staff traveled to meetings than was originally projected to gain familiarity with the entities and regional staff they would be working with.

Consultants and Contracts Expense (Actual $42,600 under budget)

- The Dynamic Reduction Study occurs every other year. SERC performed the Dynamic Reduction Study in 2013 as an unbudgeted expense, due to timing causing an under run in 2014, as the study was not performed in 2014.

Indirect Expenses (Actual $143,887 over budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
TRAINING, EDUCATION and OPERATOR CERTIFICATION	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	742,299	742,299	-	0.00%
Penalty Sanctions	97,240	97,240	-	0.00%
Total ERO Funding	**$ 839,539**	**$ 839,539**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	185,280	267,605	(82,325)	-30.76%
Interest	-	-	-	
Miscellaneous	5,907	-	5,907	
Total Funding (A)	1,030,726	1,107,144	(76,418)	-6.90%
Expenses				
Personnel Expenses				
Salaries	348,437	374,069	(25,632)	-6.85%
Payroll Taxes	24,031	22,444	1,587	7.07%
Employee Benefits	33,895	28,459	5,436	19.10%
Savings & Retirement	44,146	52,656	(8,510)	-16.16%
Total Personnel Expenses	450,509	477,628	(27,119)	-5.68%
Meeting Expenses				
Meetings	134,414	183,360	(48,946)	-26.69%
Travel	26,379	19,241	7,138	37.10%
Conference Calls	-	-	-	
Total Meeting Expenses	160,793	202,601	(41,808)	-20.64%
Operating Expenses				
Consultants & Contracts	126,270	130,000	(3,730)	-2.87%
Rent & Improvements	-	-	-	
Office Costs	1,707	320	1,387	433.44%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	127,977	130,320	(2,343)	-1.80%
Indirect Expenses	396,766	282,805	113,961	40.30%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	1,136,045	1,093,354	42,691	3.90%
Change in Assets (A - B)	(105,319)	13,790	(119,109)	-863.73%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	8,021	13,790	(5,769)	-41.83%
Total Inc(Dec) in Fixed Assets (C)	8,021	13,790	(5,769)	-41.83%
TOTAL BUDGET (B + C)	**1,144,066**	**1,107,144**	**48,460**	**4.38%**
Change in Working Capital (A-B-C)	**(113,340)**	**-**	**(124,878)**	
FTE's	**2.72**	**2.81**	**(0.09)**	**-3.20%**

Training, Education and Operator Certification
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Workshop Fees (Actual $82,325 under budget)

- SERC hosted most meetings in house or at a member's facilities, resulting in a savings in costs, and therefore an offsetting decrease in revenue allowing SERC to charge a reduced attendance fee, from when the budget was developed.
- SERC budgeted for four (4) Compliance Seminars to be held in 2014, however only hosted three (3), causing an under run.

Personnel Expenses (Actual $27,119 under budget)

- Due to turnover and the length of time to fill vacant positions, SERC is under budget in personnel expenses. SERC budgeted 2.81 FTEs in the Training program during 2014. SERC finished 2014 with 2.72 FTEs in the Training program, a difference of 0.09 FTEs.
- SERC is over budget in Payroll Taxes and Employee Benefits due to an overlap of an FTE to ensure continuity.
- SERC reclassified 0.2 FTEs of an existing budgeted position from Training and Education into General and Administrative, causing a decrease in personnel expense.

Meeting Expense (Actual $48,946 under budget)

- The under run in meetings expenses is due to a greater emphasis on hosting meetings at SERC's office and member facilities.

Indirect Expenses (Actual $113,961 over budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014 SITUATION AWARENESS and INFRASTRUCTURE SECURITY (Includes Critical Infrastructure Protection)	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	1,003,325	1,003,325	-	0.00%
Penalty Sanctions	143,611	143,611	-	0.00%
Total ERO Funding	**$ 1,146,936**	**$ 1,146,936**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	207	-	207	
Total Funding (A)	1,147,143	1,146,936	207	0.02%
Expenses				
Personnel Expenses				
Salaries	382,491	505,718	(123,227)	-24.37%
Payroll Taxes	26,591	30,343	(3,752)	-12.37%
Employee Benefits	73,950	52,881	21,069	39.84%
Savings & Retirement	45,828	61,798	(15,970)	-25.84%
Total Personnel Expenses	528,860	650,740	(121,880)	-18.73%
Meeting Expenses				
Meetings	959	10,350	(9,391)	-90.73%
Travel	39,327	47,556	(8,229)	-17.30%
Conference Calls	-	-	-	
Total Meeting Expenses	40,286	57,906	(17,620)	-30.43%
Operating Expenses				
Consultants & Contracts	16,654		16,654	
Rent & Improvements	-	-	-	
Office Costs	-	260	(260)	-100.00%
Professional Services	-	-	-	
Miscellaneous	138	-	138	
Depreciation	-	-	-	
Total Operating Expenses	16,792	260	16,532	6358.46%
Indirect Expenses	535,342	417,665	117,677	28.17%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	1,121,280	1,126,571	(5,291)	-0.47%
Change in Assets (A - B)	25,863	20,365	5,498	27.00%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	10,822	20,365	(9,543)	-46.86%
Total Inc(Dec) in Fixed Assets (C)	10,822	20,365	(9,543)	-46.86%
TOTAL BUDGET (B + C)	**1,132,102**	**1,146,936**	**4,252**	**0.37%**
Change in Working Capital (A-B-C)	**15,041**	**-**	**(4,045)**	
FTE's	**3.67**	**4.15**	**(0.48)**	**-11.57%**

Situation Awareness and Infrastructure Security
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Personnel Expenses (Actual $121,880 under budget)

- Due to turnover and the length of time to fill vacant positions, SERC is under budget in personnel expenses. SERC budgeted 4.15 FTEs in the Situation Awareness program during 2014. SERC finished 2014 with 3.67 FTEs in the Situation Awareness program, a difference of 0.48 FTEs.
- SERC reclassified 0.2 FTEs of an existing budgeted position from Situation Awareness and Infrastructure Security into General and Administrative, causing a decrease in personnel expense.
- Benefits expense is higher than budget due to unbudgeted relocation costs that were incurred in filling the vacant positions and higher usage of SERC's medical and dental benefits in 2014.

Consultants and Contracts Expense (Actual $16,654 over budget)

- To assist with short-term needs, SERC used consultants in lieu of hiring FTEs, causing SERC to be over budget.

Indirect Expenses (Actual $117,677 over budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
MEMBER FORUMS	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	-	-	-	
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	13,740	-	13,740	
Total Funding (A)	13,740	-	13,740	
Expenses				
Personnel Expenses				
Salaries	654,631	700,576	(45,945)	-6.56%
Payroll Taxes	43,889	42,035	1,854	4.41%
Employee Benefits	38,656	53,772	(15,116)	-28.11%
Savings & Retirement	76,434	94,071	(17,637)	-18.75%
Total Personnel Expenses	813,610	890,454	(76,844)	-8.63%
Meeting Expenses				
Meetings	9,635	22,300	(12,665)	-56.79%
Travel	34,552	75,139	(40,587)	-54.02%
Conference Calls	-	-	-	
Total Meeting Expenses	44,187	97,439	(53,252)	-54.65%
Operating Expenses				
Consultants & Contracts	16,654	-	16,654	
Rent & Improvements	-	-	-	
Office Costs	649	365	284	77.81%
Professional Services	777	-	777	
Miscellaneous	311	-	311	
Depreciation	-	-	-	
Total Operating Expenses	18,391	365	18,026	4938.63%
Indirect Expenses	(876,188)	(988,258)	112,070	-11.34%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	13,740	-	13,740	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	**-**	**-**	**-**	
Change in Working Capital (A-B-C)	**13,740**	**-**	**13,740**	
FTE's	**4.15**	**4.83**	**(0.68)**	**-14.08%**

Technical Committees and Member Forums
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Miscellaneous Income (Actual $13,740 over budget)

- Amount represents contractual repayment of employee benefits, causing the unplanned over run.

Personnel Expenses (Actual $76,844 under budget)

- Due to turnover and the length of time to fill vacant positions, SERC is under budget in personnel expenses. SERC budgeted 4.83 FTEs in the Technical Committees program during 2014. SERC finished 2014 with 4.15 FTEs in the Technical Committees program, a difference of 0.68 FTEs.
- SERC reclassified 0.2 FTEs of an existing budgeted position from Technical Committees and Member Forums into General and Administrative, causing a decrease in personnel expense.

Meeting Expense (Actual $12,665 under budget)

- The under run in meetings expenses is due to a greater emphasis on hosting meetings at SERC's office and member facilities.

Travel Expense (Actual $40,587 under budget)

- Due to the open positions, SERC has had less staff travel. Additionally, SERC has put a greater emphasis on hosting meetings in the Charlotte office, causing a decrease in travel expenses.

Consultants and Contracts Expense (Actual $16,654 over budget)

- To assist with short-term needs, SERC used consultants in lieu of hiring FTEs, causing SERC to be over budget.

Indirect Expenses (Actual $112,070 under budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
GENERAL and ADMINISTRATIVE	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	(788,684)	(788,684)	-	0.00%
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ (788,684)**	**$ (788,684)**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	302,637	276,500	26,137	9.45%
Total Funding (A)	(486,047)	(512,184)	26,137	-5.10%
Expenses				
Personnel Expenses				
Salaries	2,496,809	2,342,145	154,664	6.60%
Payroll Taxes	141,725	140,529	1,196	0.85%
Employee Benefits	174,037	163,447	10,590	6.48%
Savings & Retirement	232,829	322,636	(89,807)	-27.84%
Total Personnel Expenses	3,045,400	2,968,757	76,643	2.58%
Meeting Expenses				
Meetings	66,038	47,185	18,853	39.96%
Travel	86,027	82,503	3,524	4.27%
Conference Calls	39,099	48,000	(8,901)	-18.54%
Total Meeting Expenses	191,164	177,688	13,476	7.58%
Operating Expenses				
Consultants & Contracts	216,043	180,000	36,043	20.02%
Rent & Improvements	798,011	419,861	378,150	90.07%
Office Costs	522,980	250,380	272,600	108.87%
Professional Services	27,530	25,000	2,530	10.12%
Miscellaneous	10,491	-	10,491	
Depreciation	277,062	218,653	58,409	26.71%
Total Operating Expenses	1,852,117	1,093,894	758,223	69.31%
Indirect Expenses	(5,094,751)	(4,255,339)	(839,412)	19.73%
Other Non-Operating Expenses	6,070	15,000	(8,930)	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	(486,047)	(512,184)	26,137	-5.10%
Fixed Assets				
Depreciation	(277,062)	(218,653)	(58,409)	26.71%
Computer & Software CapEx	227,998	460,000	(232,002)	-50.44%
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	50,000	(50,000)	-100.00%
Leasehold Improvements	187,453	-	187,453	
Incr(Dec) in Fixed Assets	(138,389)	(291,347)	152,958	
Allocation of Fixed Assets	(138,389)	(291,347)	152,958	-52.50%
Total Inc(Dec) in Fixed Assets (C)	(276,778)	(582,694)	305,916	-52.50%
TOTAL BUDGET (B + C)	**(276,778)**	**(582,694)**	**(305,916)**	**52.50%**
Change in Working Capital (A-B-C)	**(209,269)**	**70,510**	**332,053**	470.93%
FTE's	**17.46**	**15.00**	**2.46**	**16.40%**

General and Administrative
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Personnel Expenses (Actual $76,643 over budget)

- SERC reclassified three existing positions into General and Administrative that were budgeted in Compliance, Reliability Assessments, Reliability Standards, Training and Education, Situation Awareness and Infrastructure Security, and Technical Committees and Member Forums, causing an increase in personnel expense.
- Due to the staffing transitions, SERC's retirement costs are under budget as SERC did not incur a full year of expenses related to the company portion match and supplemental contributions for unfilled positions.

Meeting Expense (Actual $18,853 over budget)

- The over run in meetings expenses is due to actual costs for meeting spaces being greater than anticipated in the budget, as well as costs for additional in-house meetings.

Consultants and Contracts Expense (Actual $36,043 over budget)

- To assist with short-term needs, SERC used consultants in lieu of hiring FTEs, causing SERC to be over budget.

Rent Expense (Actual $378,150 over budget)

- SERC signed a new lease, with a commencement date of April 1, 2014, which included ten months of free rent. GAAP requires rent to be recorded on a straight line basis, accounting for the free rent. SERC did not incur actual rent expense for the new office space. However, due to accounting principles, an entry for the new space was recorded on a straight line basis. An off-setting entry was recorded as a liability on the balance sheet.

Office Costs (Actual $272,600 over budget)

- At the time the 2014 budget was developed, SERC anticipated relocating into the new space during 2013, and therefore budgeted a small amount for the purchase of office furniture to furnish the new office space in 2014. Due to delays in the relocation, a significant amount of the furniture was purchased in 2014, causing the over run.

Miscellaneous Expense (Actual $10,491 over budget)

- Miscellaneous expense includes recognition for staff and SERC members. These items were not budgeted, causing an over run.

Fixed Assets (Actual $152,958 under budget)

- Due to the actual cost of the assets and the timing of when the assets were placed into service, depreciation expense was higher than the budget, causing the overrun.
- Due to delays in several software projects, including SERC's website and portal development, SERC is under budget.

- The 2014 budget included equipment for the new office space. This equipment was purchased in 2013, causing the under run.
- SERC anticipated relocating office space in 2013, and therefore did not budget for costs associated with the construction in the 2014 budget. Due to the delay in the relocation, a significant amount of the construction costs were incurred in 2014, causing the over run.

Indirect Expenses (Actual $839,412 over budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
LEGAL and REGULATORY	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	-	-	-	
Penalty Sanctions	-	-	-	
Total ERO Funding	$ -	$ -	$ -	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	-	-	-	
Expenses				
Personnel Expenses				
Salaries	-	-	-	
Payroll Taxes	-	-	-	
Employee Benefits	-	-	-	
Savings & Retirement	-	-	-	
Total Personnel Expenses	-	-	-	
Meeting Expenses				
Meetings	-	-	-	
Travel	-	-	-	
Conference Calls	-	-	-	
Total Meeting Expenses	-	-	-	
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	2,465	1,900	565	29.74%
Professional Services	54,620	35,000	19,620	56.06%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	57,085	36,900	20,185	54.70%
Indirect Expenses	(57,085)	(36,900)	(20,185)	54.70%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	-	-	-	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	-	-	-	
Change in Working Capital (A-B-C)	-	-	-	
FTE's	-	-	-	

Legal and Regulatory
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Professional Services (Actual $19,620 over budget)

- SERC incurred additional legal services to assist with corporate matters including changing SERC's state of incorporation from Alabama to North Carolina.

Indirect Expenses (Actual $20,185 over budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014					
INFORMATION TECHNOLOGY		**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding					
	ERO Funding				
	Assessments	-	-	-	
	Penalty Sanctions	-	-	-	
	Total ERO Funding	**$ -**	**$ -**	**$ -**	
	Federal Grants	-	-	-	
	Membership Fees	-	-	-	
	Testing	-	-	-	
	Services & Software	-	-	-	
	Workshop Fees	-	-	-	
	Interest	-	-	-	
	Miscellaneous	-	-	-	
Total Funding (A)		-	-	-	
Expenses					
	Personnel Expenses				
	Salaries	-	-	-	
	Payroll Taxes	-	-	-	
	Employee Benefits	-	-	-	
	Savings & Retirement	-	-	-	
	Total Personnel Expenses	-	-	-	
	Meeting Expenses				
	Meetings	-	-	-	
	Travel	-	-	-	
	Conference Calls	-	-	-	
	Total Meeting Expenses	-	-	-	
	Operating Expenses				
	Consultants & Contracts	574,070	441,530	132,540	30.02%
	Rent & Improvements	-	-	-	
	Office Costs	190,458	197,340	(6,882)	-3.49%
	Professional Services	-	-	-	
	Miscellaneous	-	-	-	
	Depreciation	-	-	-	
	Total Operating Expenses	764,528	638,870	125,658	19.67%
	Indirect Expenses	(764,528)	(638,870)	(125,658)	19.67%
	Other Non-Operating Expenses	-	-	-	
Total Expenses (B)		-	-	-	
Change in Assets (A - B)		-	-	-	
Fixed Assets					
	Depreciation	-	-	-	
	Computer & Software CapEx	-	-	-	
	Furniture & Fixtures CapEx	-	-	-	
	Equipment CapEx	-	-	-	
	Leasehold Improvements	-	-	-	
	Incr(Dec) in Fixed Assets	-	-	-	
	Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)		-	-	-	
TOTAL BUDGET (B + C)		-	-	-	
Change in Working Capital (A-B-C)		-	-	-	
FTE's		-	-	-	

Information Technology
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

Consultants and Contracts (Actual $132,540 over budget)

- To assist with short-term needs, SERC used consultants in lieu of hiring FTEs, causing SERC to be over budget.
- SERC used consultants for maintenance on the current tools and to develop unbudgeted software projects, all below SERC's capitalization policy, and therefore expensed the amounts, causing the over run.

Indirect Expenses (Actual $125,658 over budget)

- Expenses related to indirect programs have been allocated proportionately to the direct programs for 2014 based on the number of FTEs in those programs.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
HUMAN RESOURCES	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	-	-	-	
Penalty Sanctions	-	-	-	
Total ERO Funding	$ -	$ -	$ -	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	-	-	-	
Expenses				
Personnel Expenses				
Salaries	-	-	-	
Payroll Taxes	-	-	-	
Employee Benefits	-	-	-	
Savings & Retirement	-	-	-	
Total Personnel Expenses	-	-	-	
Meeting Expenses				
Meetings	-	-	-	
Travel	-	-	-	
Conference Calls	-	-	-	
Total Meeting Expenses	-	-	-	
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	1,149	360	789	219.17%
Professional Services	8,421	10,000	(1,579)	-15.79%
Miscellaneous	1,440	-	1,440	
Depreciation	-	-	-	
Total Operating Expenses	11,010	10,360	650	6.27%
Indirect Expenses	(11,010)	(10,360)	(650)	6.27%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	-	-	-	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	-	-	-	
Change in Working Capital (A-B-C)	-	-	-	
FTE's	-	-	-	

Human Resources
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

There are no variances requiring explanation.

SERC Reliability Corporation Statement of Activities From 1/1/2014 through 12/31/2014				
ACCOUNTING and FINANCE	**2014 Actual**	**2014 Budget**	**2014 Variance from Budget Over(Under)**	
Funding				
ERO Funding				
Assessments	-	-	-	
Penalty Sanctions	-	-	-	
Total ERO Funding	$ -	$ -	$ -	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	2,054	10,000	(7,946)	-79.46%
Miscellaneous	-	-	-	
Total Funding (A)	2,054	10,000	(7,946)	-79.46%
Expenses				
Personnel Expenses				
Salaries	-	-	-	
Payroll Taxes	-	-	-	
Employee Benefits	-	-	-	
Savings & Retirement	-	-	-	
Total Personnel Expenses	-	-	-	
Meeting Expenses				
Meetings	-	-	-	
Travel	-	-	-	
Conference Calls	-	-	-	
Total Meeting Expenses	-	-	-	
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	15,832	10,000	5,832	58.32%
Professional Services	26,270	35,400	(9,130)	-25.79%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	42,102	45,400	(3,298)	-7.26%
Indirect Expenses	(42,102)	(45,400)	3,298	-7.26%
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	2,054	10,000	(7,946)	-79.46%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	-	-	-	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	-	-	-	
TOTAL BUDGET (B + C)	-	-	-	
Change in Working Capital (A-B-C)	**2,054**	**10,000**	**(7,946)**	-79.46%
FTE's	-	-	-	

Accounting and Finance
Variance Explanations as of December 31, 2014
Variances > +/- $10,000 and 10%

There are no variances requiring explanation.

SERC RELIABILITY CORPORATION

FINANCIAL STATEMENTS AND
SUPPLEMENTAL SCHEDULES

As of and for the Year Ended December 31, 2014 and 2013

And Report of Independent Auditor

Cherry Bekaert LLP
CPAs & Advisors

SERC RELIABILITY CORPORATION

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Cherry Bekaert LLP
CPAs & Advisors

Report of Independent Auditor

To the Board of Directors
SERC Reliability Corporation
Charlotte, North Carolina

Report on the Financial Statements

We have audited the accompanying financial statements of SERC Reliability Corporation (the "Corporation"), which comprise the statements of financial position as of December 31, 2014 and 2013, and the related statements of activities and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of SERC Reliability Corporation as of December 31, 2014 and 2013, and the changes in net assets and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Supplemental Schedules

Our audits were conducted for the purpose of forming an opinion on the financial statements as a whole. The supplemental schedules on pages 10 through 13 are presented for purposes of additional analysis and are not a required part of the financial statements. Such information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the financial statements. The information has been subjected to the auditing procedures applied in the audits of the financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the financial statements or to the financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the information is fairly stated in all material respects in relation to the financial statements as a whole.

Cherry Bekaert LLP

Charlotte, North Carolina
April 20, 2015

SERC RELIABILITY CORPORATION

STATEMENTS OF FINANCIAL POSITION

DECEMBER 31, 2014 AND 2013

	2014	2013
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,325,763	$ 7,685,935
Accounts receivable	896,504	68,691
Prepaid expenses and other current assets	184,338	172,213
Total Current Assets	8,406,605	7,926,839
Property and equipment, net	800,868	662,478
Total Assets	$ 9,207,473	$ 8,589,317
LIABILITIES AND NET ASSETS		
Current Liabilities:		
Accounts payable	$ 333,364	$ 452,530
Accrued salaries and related benefits	1,985,230	2,407,098
Deferred revenue	2,165,519	2,318,183
Total Current Liabilities	4,484,113	5,177,811
Deferred rent	385,234	-
Total Liabilities	4,869,347	5,177,811
Net Assets:		
Unrestricted and undesignated	1,238,126	2,215,987
Unrestricted and designated operating reserve	3,100,000	1,195,519
Total Net Assets	4,338,126	3,411,506
Total Liabilities and Net Assets	$ 9,207,473	$ 8,589,317

The accompanying notes to the financial statements are an integral part of these statements.

SERC RELIABILITY CORPORATION

STATEMENTS OF ACTIVITIES

YEARS ENDED DECEMBER 31, 2014 AND 2013

	2014	2013
Funding		
Member assessments	$ 13,734,499	$ 13,829,878
Penalty sanctions	2,054,500	51,000
Workshops	185,280	173,997
Interest	2,054	1,271
Miscellaneous	354,912	238,996
Total funding	16,331,245	14,295,142
Expenses		
Personnel expenses:		
Salaries	8,694,787	9,176,085
Payroll taxes	580,037	632,913
Employee benefits	876,645	896,790
Savings and retirement	1,048,875	1,169,319
Total personnel expenses	11,200,344	11,875,107
Meeting expenses:		
Meetings	256,954	276,839
Travel	480,897	646,398
Conference calls	39,099	49,760
Total meeting expenses	776,950	972,997
Operating expenses:		
Contracts and consultants	1,449,604	1,410,698
Rent and improvements	798,011	403,731
Office costs	750,881	633,768
Professional services	131,166	107,705
Depreciation	277,062	137,147
Miscellaneous	20,607	2,148
Total operating expenses	3,427,331	2,695,197
Total expenses	15,404,625	15,543,301
Change in net assets	926,620	(1,248,159)
Net assets		
Beginning of year	3,411,506	4,659,665
End of year	$ 4,338,126	$ 3,411,506

The accompanying notes to the financial statements are an integral part of these statements.

SERC RELIABILITY CORPORATION

STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31, 2014 AND 2013

	2014	2013
Cash flows from operating activities:		
Change in net assets	$ 926,620	$ (1,248,159)
Adjustments to reconcile change in net assets to net cash provided by operating activities:		
Depreciation	277,062	137,147
Changes in operating assets and liabilities:		
Accounts receivable	(33,103)	(50,204)
Prepaid expenses and other current assets	(12,125)	(44,810)
Accounts payable	(119,166)	(12,989)
Accrued salaries and related benefits	(421,868)	425,278
Deferred rent	385,234	-
Deferred revenue	(152,664)	1,761,577
Net cash provided by operating activities	849,990	967,840
Cash flows from investing activities:		
Additions to property and equipment	(415,452)	(474,813)
Receivable for reimbursement of upfit costs	(794,710)	-
Net cash used in investing activities	(1,210,162)	(474,813)
Net (decrease) increase in cash and cash equivalents	(360,172)	493,027
Cash and cash equivalents		
Beginning of year	7,685,935	7,192,908
End of year	$ 7,325,763	$ 7,685,935

The accompanying notes to the financial statements are an integral part of these statements.

Note 1—Organization and nature of operations

SERC Reliability Corporation (the "Corporation") is a non-profit corporation which qualifies as a Regional Reliability Organization under the Energy Policy Act of 2005. The Corporation's mission is to promote the reliability of the electricity supply for the southeastern United States. The activities of the Corporation are directed by its Board of Directors. The Corporation's members are electricity suppliers, brokers and consumers from various ownership segments of the electricity supply industry, investor-owned utilities rural electric cooperatives, municipal utilities, independent power producers, power marketers and customers. These entities account for virtually all the electricity supplied in the southeastern United States.

Note 2—Summary of significant accounting policies

Accounting Principles - The financial statements of the Corporation have been prepared on the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The Corporation is required to report information regarding its financial position and activities according to three classes of net assets - unrestricted net assets, temporarily restricted net assets and permanently restricted net assets. The Corporation had only unrestricted net assets as of December 31, 2014 and 2013, including unrestricted net assets that have been designated by the Board of Directors as an operating reserve.

Management Estimates - The preparation of financial statements in conformity with GAAP requires management to make estimates, including estimates relating to assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

Cash and Cash Equivalents - The Corporation considers all cash investments with an original maturity of three months or less to be cash equivalents.

Accounts Receivable - Accounts receivable arise primarily from amounts billed to members. Management's determination of the need for an allowance for doubtful accounts is based on evaluation of the accounts receivable, past experience, current economic conditions and other risks inherent in the accounts receivable portfolio. Any amounts considered to be uncollectible are written off at the time of such determination. At December 31, 2014 and 2013, management has determined that an allowance for doubtful accounts is not necessary. As of December 31, 2014, accounts receivable includes $794,710 from the lessor referred to in Note 4 as an allowance for the upfit of lease office space.

Property and Equipment - Property and equipment are stated at cost. Depreciation is computed using the straight-line method over the estimated economic useful lives of the assets ranging from 5-7 years for leasehold improvements and 3 years for computer equipment and software. The costs of major improvements are capitalized, while the costs of maintenance and repairs, which do not improve or extend the lives of the respective assets, are expensed currently. The cost and accumulated depreciation of property and equipment are eliminated from the accounts upon disposal, and any resulting gain or loss is included in the change in net assets of the Corporation. Long-lived assets held and used by the Corporation are reviewed for impairment whenever changes in circumstances indicate the carrying value of an asset may not be recoverable.

Deferred Revenue - Deferred revenue represents amounts billed or collected from members in advance of the periods in which such amounts are earned.

Note 2—Summary of significant accounting policies (continued)

Revenue Recognition - All income is recognized in the period when earned. The Corporation receives a significant portion of its funding directly from the North American Electric Reliability Corporation ("NERC") based on the budget submitted by the Corporation and approved by NERC and the Federal Energy Regulatory Commission ("FERC"). The revenue is received in four equal quarterly installments received at the beginning of each quarter. Based on past history with NERC, the Corporation believes that its revenue risk exposure is limited.

Income Taxes - The Corporation is exempt from federal and state income taxes under Section 501(c)(6) of the Internal Revenue Code ("IRC") and the applicable state statutes. Management believes that the Corporation continues to satisfy the requirements of a tax exempt organization and is not subject to tax. Accordingly, no provision for income taxes has been recorded in the accompanying financial statements.

Management has evaluated the effect of the Financial Accounting Standards Board ("FASB") guidance on accounting for uncertainty in income taxes. The guidance clarifies the accounting for uncertainty in income taxes recognized in an entity's financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Corporation's policy is to record a liability for any tax position taken that is beneficial to the Corporation, including any related interest and penalties, when it is more likely than not the position taken by management with respect to a transaction or class of transactions will be overturned by a taxing authority upon examination. Management believes there are no such positions at December 31, 2014 or 2013 and, accordingly, no liability has been accrued. The Corporation is no longer subject to tax examinations for years prior to 2011.

Note 3—Property and equipment

Property and equipment includes the following at December 31:

	2014	2013
Leasehold improvements	$ 240,552	$ 53,099
Computer equipment	153,409	202,048
Software	1,138,179	918,535
	1,532,140	1,173,682
Less: Accumulated depreciation	(731,272)	(511,204)
Property and equipment, net	$ 800,868	$ 662,478

Depreciation expense was $277,062 and $137,147 for the years ended December 2014 and 2013, respectively.

Note 4—Leases

The Corporation leased office facilities under three operating leases which expired in January 2015. The leases called for monthly payments ranging from $32,000 to $35,000.

Note 4—Leases (continued)

During the year ended December 31, 2014, the Corporation entered into an operating lease for office space which commenced on April 1, 2014 and continues through March 31, 2025. The lease provides free rent for the first 10 months of the lease period and annual rent payments ranging from $460,000 to $612,000 thereafter. In connection with the new office space, the Corporation entered into a construction agreement providing for an upfit allowance, whereby the Corporation will be reimbursed for upfit costs up to $794,710. This amount was included in the accounts receivable balance on the statement of financial position for the year ended December 31, 2014.

Total rent expense for the years ended December 31, 2014 and 2013, was $798,011 and $403,731, respectively.

Future minimum payments on all operating leases are as follows:

Year ending December 31,	
2015	$ 495,442
2016	512,767
2017	524,304
2018	536,101
2019	548,163
Thereafter	2,982,614
Total	$ 5,599,391

Note 5—Line of credit

The Corporation has a $1,000,000 bank line of credit at an interest rate of prime plus 0.9%, limited to a 5.0% floor, (5.0% at December 31, 2014) for which all outstanding borrowings shall be payable in full at maturity on August 30, 2015. The line is secured by the assets of the Corporation. The line of credit had no outstanding balance at December 31, 2014 and 2013.

Note 6—Benefit plans

401(k) plan - The Corporation sponsors a 401(k) retirement plan covering all eligible employees, as defined. The Corporation makes an annual contribution to the plan equal to 3% of each eligible employee's compensation. In addition, the plan provides that the Corporation may make additional discretionary matching and profit-sharing contributions. During the years ended December 31, 2014 and 2013, contribution expense related to the plan totaled $1,024,327 and $1,131,588, respectively.

Deferred compensation plan - The Corporation established a deferred compensation plan in accordance with Internal Revenue Code Section 457(b) for certain employees, as defined. The plan provides that eligible employees may make elective salary reduction contributions in accordance with limitations established by the Internal Revenue Code. In addition, the Corporation may make discretionary contributions as provided in the plan. During the years ended December 31, 2014 and 2013, contribution expense related to the plan totaled $8,641 and $21,036, respectively. The asset and liability for deferred compensation of $90,832 and $82,204 at December 31, 2014 and 2013, respectively, is included in prepaid expenses and other current assets and accrued salaries and related benefits in the accompanying statements of financial position.

Note 7—Concentrations of credit risk and uncertainties

The Corporation places its cash and cash equivalents on deposit with a North Carolina financial institution. The Federal Deposit Insurance Company ("FDIC") covers $250,000 for substantially all depository accounts. The Corporation from time to time may have balances in excess of the FDIC insured limits. The Corporation had funds in banks in excess of the federally insured limits of $6,970,366 and $7,343,667 at December 31, 2014 and 2013, respectively.

Note 8—Functional expenses

The following is an allocation of expenses by functional category for the years ended December 31:

	2014	2013
Program expenses:		
Reliability standards	$ 140,024	$ 291,074
Compliance enforcement	5,822,363	6,928,256
Reliability assessment	1,271,357	1,265,510
Training and education	739,279	635,463
Situation awareness	585,938	557,238
	8,558,961	9,677,541
Committee and member forums	876,188	853,769
General and administrative expenses:		
General and administrative	5,094,751	4,391,004
Legal and regulatory	57,085	27,362
Information technology	764,528	532,388
Human resources	11,010	17,674
Accounting and finance	42,102	43,563
	5,969,476	5,011,991
Total	$ 15,404,625	$ 15,543,301

Note 9—Subsequent events

Management has evaluated subsequent events through April 20, 2015, the date the financial statements were issued.

ACCOMPANYING INFORMATION

SERC RELIABILITY CORPORATION
STATUTORY FINANCIAL STATEMENTS

YEAR ENDED DECEMBER 31, 2014

	2014 YTD Actual	2014 YTD Budget	2014 YTD Variance
Funding			
Member assessments	$ 13,734,499	$ 13,734,499	$ -
Penalty sanctions	2,054,500	2,054,500	-
Workshops	185,280	267,605	(82,325)
Interest	2,054	10,000	(7,946)
Miscellaneous	354,912	308,500	46,412
Total funding	16,331,245	16,375,104	(43,859)
Expenses			
Personnel expenses:			
Salaries	8,694,787	10,187,444	(1,492,657)
Payroll taxes	580,037	611,246	(31,209)
Employee benefits	876,645	941,806	(65,161)
Savings and retirement	1,048,875	1,394,422	(345,547)
Total personnel expenses	11,200,344	13,134,918	(1,934,574)
Meeting expenses:			
Meetings	256,954	317,195	(60,241)
Travel	480,897	605,484	(124,587)
Conference calls	39,099	48,000	(8,901)
Total meeting expenses	776,950	970,679	(193,729)
Operating expenses:			
Contracts and consultants	1,449,604	1,229,030	220,574
Rent and improvements	798,011	419,861	378,150
Office costs	750,881	477,400	273,481
Professional services	131,166	120,400	10,766
Depreciation	277,062	218,653	58,409
Miscellaneous	20,607	15,000	5,607
Total operating expenses	3,427,331	2,480,344	946,987
Total expenses	15,404,625	16,585,941	(1,181,316)
Change in net assets	$ 926,620	$ (210,837)	$ 1,137,457

SERC RELIABILITY CORPORATION
STATUTORY FINANCIAL STATEMENTS

YEAR ENDED DECEMBER 31, 2013

	2013 YTD Actual	2013 YTD Budget	2013 YTD Variance
Funding			
Member assessments	$ 13,829,878	$ 13,829,878	$ -
Penalty sanctions	51,000	51,000	-
Workshops	173,997	246,000	(72,003)
Interest	1,271	10,000	(8,729)
Miscellaneous	238,996	65,000	173,996
Total funding	14,295,142	14,201,878	93,264
Expenses			
Personnel expenses:			
Salaries	9,176,085	9,925,148	(749,063)
Payroll taxes	632,913	595,509	37,404
Employee benefits	896,790	916,100	(19,310)
Savings and retirement	1,169,319	1,353,524	(184,205)
Total personnel expenses	11,875,107	12,790,281	(915,174)
Meeting expenses:			
Meetings	276,839	309,160	(32,321)
Travel	646,398	595,023	51,375
Conference calls	49,760	60,000	(10,240)
Total meeting expenses	972,997	964,183	8,814
Operating expenses:			
Contracts and consultants	1,410,698	1,166,947	243,751
Rent and improvements	403,731	405,407	(1,676)
Office costs	633,768	361,552	272,216
Professional services	107,705	105,900	1,805
Depreciation	137,147	300,389	(163,242)
Miscellaneous	2,148	-	2,148
Total operating expenses	2,695,197	2,340,195	355,002
Total expenses	15,543,301	16,094,659	(551,358)
Change in net assets	$ (1,248,159)	$ (1,892,781)	$ 644,622

SERC RELIABILITY CORPORATION

STATUTORY FINANCIAL STATEMENTS BY FUNCTION

YEAR ENDED DECEMBER 31, 2014

	300 RELIAB STD DEV	400 COMP ENFORCE/ ORG REG & CERT	800 RELIAB ASSES	900 TRAINING & EDUC	1000 SIT AWARE	1100 COMMITTEE & MBR FORUMS	2000 GENERAL ADMIN	2200 LEGAL & REGULATORY	2300 IT	2400 HUMAN RESOURCES	2500 ACCOUNTING & FINANCE	2014 YTD Actual	2014 YTD Budget	2014 YTD Variance
Funding														
Member assessments	466,802	10,372,696	1,938,061	742,299	1,003,325	$ -	(788,684)	$ -	$ -	$ -	$ -	$ 13,734,499	$ 13,734,499	$ -
Penalty sanctions	79,938	1,470,713	262,998	97,240	143,611	-	-	-	-	-	-	2,054,500	2,054,500	-
Workshops	-	-	-	185,280	-	-	-	-	-	-	-	185,280	267,605	(82,325)
Interest	-	-	-	-	-	-	-	-	-	-	2,054	2,054	10,000	(7,946)
Miscellaneous	200	31,465	756	5,907	207	13,740	302,637	-	-	-	-	354,912	308,500	46,412
Total funding	546,940	11,874,874	2,201,815	1,030,726	1,147,143	13,740	(486,047)	-	-	-	2,054	16,331,245	16,375,104	(43,859)
Expenses														
Personnel expenses:														
Salaries	78,760	4,024,180	709,479	348,437	382,491	654,631	2,496,809	-	-	-	-	8,694,787	10,187,444	(1,492,657)
Payroll taxes	5,844	279,538	58,419	24,031	26,591	43,889	141,725	-	-	-	-	580,037	611,246	(31,209)
Employee benefits	23,878	396,358	135,871	33,895	73,950	38,656	174,037	-	-	-	-	876,645	941,806	(65,161)
Savings and retirement	12,893	554,549	82,196	44,146	45,828	76,434	232,829	-	-	-	-	1,048,875	1,394,422	(345,547)
Total personnel expenses	121,375	5,254,625	985,965	450,509	528,860	813,610	3,045,400	-	-	-	-	11,200,344	13,134,918	(1,934,574)
Meeting expenses:														
Meetings	300	16,348	29,260	134,414	959	9,635	66,038	-	-	-	-	256,954	317,195	(60,241)
Travel	1,395	231,063	62,154	26,379	39,327	34,552	86,027	-	-	-	-	480,897	605,484	(124,587)
Conference calls	-	-	-	-	-	-	39,099	-	-	-	-	39,099	48,000	(8,901)
Total meeting expenses	1,695	247,411	91,414	160,793	40,286	44,187	191,164	-	-	-	-	776,950	970,679	(193,729)
Operating expenses:														
Contracts and consultants	16,654	293,359	189,900	126,270	16,654	16,654	216,043	-	574,070	-	-	1,449,604	1,229,030	220,574
Rent and improvements	-	-	-	-	-	-	798,011	-	-	-	-	798,011	419,861	378,150
Office costs	-	12,930	2,711	1,707	-	649	522,980	2,465	190,458	1,149	15,832	750,881	477,400	273,481
Professional services	-	13,467	81	-	-	777	27,530	54,620	-	8,421	26,270	131,166	120,400	10,766
Depreciation	-	-	-	-	-	-	277,062	-	-	-	-	277,062	218,653	58,409
Miscellaneous	300	571	1,286	-	138	311	16,561	-	-	1,440	-	20,607	15,000	5,607
Total operating expenses	16,954	320,327	193,978	127,977	16,792	18,391	1,858,187	57,085	764,528	11,010	42,102	3,427,331	2,480,344	946,987
Total expenses	140,024	5,822,363	1,271,357	739,279	585,938	876,188	5,094,751	57,085	764,528	11,010	42,102	15,404,625	16,585,941	(1,181,316)
Change in net assets	$ 406,916	$ 6,052,511	$ 930,458	$ 291,447	$ 561,205	$ (862,448)	$ (5,580,798)	$ (57,085)	$ (764,528)	$ (11,010)	$ (40,048)	$ 926,620	$ (210,837)	$ 1,137,457

SERC RELIABILITY CORPORATION

STATUTORY FINANCIAL STATEMENTS BY FUNCTION

YEAR ENDED DECEMBER 31, 2013

	300 RELIAB STD DEV	400 COMP ENFORCE/ ORG REG & CERT	800 RELIAB ASSES	900 TRAINING & EDUC	1000 SIT AWARE	1100 COMMITTEE MBR FORUMS	2000 GENERAL ADMIN	2200 LEGAL & REGULATORY	2300 IT	2400 HUMAN RESOURCES	2500 ACCOUNTING & FINANCE	2013 YTD Actual	2013 YTD Budget	2013 YTD Variance
Funding														
Member assessments	$ 698,880	$ 11,150,647	$ 1,937,756	$ 701,400	$ 1,046,920	-	$ (1,705,725)	-	-	-	-	$ 13,829,878	$ 13,829,878	$ -
Penalty sanctions	2,358	36,796	6,384	2,137	3,325	-	-	-	-	-	-	51,000	51,000	-
Workshops	-	-	-	173,997	-	-	-	-	-	-	-	173,997	246,000	(72,003)
Interest	-	-	-	-	-	-	-	-	-	-	1,271	1,271	10,000	(8,729)
Miscellaneous	87	177,319	-	87	87	87	61,329	-	-	-	-	238,996	65,000	173,996
Total funding	701,325	11,364,762	1,944,140	877,621	1,050,332	87	(1,644,396)	-	-	-	1,271	14,295,142	14,201,878	93,264
Expenses														
Personnel expenses:														
Salaries	226,234	4,556,726	723,751	300,729	380,862	639,983	2,347,800	-	-	-	-	9,176,085	9,925,148	(749,063)
Payroll taxes	17,470	331,116	56,925	20,837	20,980	46,782	138,803	-	-	-	-	632,913	595,509	37,404
Employee benefits	26,540	470,656	93,610	27,231	32,467	57,156	189,130	-	-	-	-	896,790	916,100	(19,310)
Savings and retirement	13,925	636,236	93,427	35,589	61,989	65,562	262,591	-	-	-	-	1,169,319	1,353,524	(184,205)
Total personnel expenses	284,169	5,994,734	967,713	384,386	496,298	809,483	2,938,324	-	-	-	-	11,875,107	12,790,281	(915,174)
Meeting expenses:														
Meetings	302	26,743	28,428	142,043	3,225	11,598	64,500	-	-	-	-	276,839	309,160	(32,321)
Travel	5,804	407,579	69,856	13,986	55,399	28,345	65,429	-	-	-	-	646,398	595,023	51,375
Conference calls	-	-	-	-	-	-	49,760	-	-	-	-	49,760	60,000	(10,240)
Total meeting expenses	6,106	434,322	98,284	156,029	58,624	39,943	179,689	-	-	-	-	972,997	964,183	8,814
Operating expenses:														
Contracts and consultants	-	474,637	194,865	90,077	-	2,756	211,984	-	424,779	10,000	1,600	1,410,698	1,166,947	243,751
Rent and improvements	-	-	-	-	-	-	403,731	-	-	-	-	403,731	405,407	(1,676)
Office costs	799	16,050	4,648	4,971	2,316	1,477	481,725	1,215	107,609	699	12,259	633,768	361,552	272,216
Professional services	-	8,513	-	-	-	-	37,366	26,147	-	6,975	28,704	107,705	105,900	1,805
Depreciation	-	-	-	-	-	-	137,147	-	-	-	-	137,147	300,389	(163,242)
Miscellaneous	-	-	-	-	-	110	1,038	-	-	-	1,000	2,148	-	2,148
Total operating expenses	799	499,200	199,513	95,048	2,316	4,343	1,272,991	27,362	532,388	17,674	43,563	2,695,197	2,340,195	355,002
Total expenses	291,074	6,928,256	1,265,510	635,463	557,238	853,769	4,391,004	27,362	532,388	17,674	43,563	15,543,301	16,094,659	(551,358)
Change in net assets	$ 410,251	$ 4,436,506	$ 678,630	$ 242,158	$ 493,094	$ (853,682)	$ (6,035,400)	$ (27,362)	$ (532,388)	$ (17,674)	$ (42,292)	$ (1,248,159)	$ (1,892,781)	$ 644,622

ATTACHMENT 7

2014 ACTUAL COST-TO-BUDGET COMPARISON

FOR

SOUTHWEST POWER POOL REGIONAL ENTITY

AND

2014 AUDITED FINANCIAL REPORT

FOR

SOUTHWEST POWER POOL, INC.

Deborah K. Currie
Manager of Regulatory Interface and Process Improvement

Southwest Power Pool Regional Entity
201 Worthen Dr.
Little Rock, AR 72223
P 501.688.8228
F 501.482.2025

April 29, 2015 ***Via Electronic Mail***

Michael Walker, Chief Financial Officer
Susan Turpen, Controller
North American Electric Reliability Corporation
3343 Peachtree Road, NE
4th Floor East Tower – Suite 400
Atlanta, GA 30326

Subject: Southwest Power Pool Regional Entity 2014 Actual Cost-to-Budget Comparison

Dear Mr. Walker and Ms. Turpen,

Attached is the Southwest Power Pool, Inc.'s (SPP, Inc.) submission of the SPP Regional Entity's (SPP RE) 2014 Actual Cost-to-Budget Comparison (2014 True Up Filing). For 2014, the SPP RE received approximately $9.7 million in statutory funds and incurred approximately $9.8 million in statutory expense (compared to $11.8 million budget).

The $2.7 thousand funding variance results from interest earned on the cash balance. The SPP RE performs only statutory activities, and therefore no statutory funding was used for non-statutory activities. The net impact on SPP RE's cash position for the year was a $88 thousand negative variance (compared to the budgeted $2.1 million negative variance).

The significant expense variances at the aggregate statutory level are explained below, while the explanations for the expense variances by statutory program area are provided in Attachment 1.

Aggregate Expense Variances

- **Personnel Expenses** (Actual - $4,281K or 13% below budget) – Personnel expenses were less than budget primarily due to four positions (Director of Compliance and Events, two Lead Engineers and a CIP Compliance Specialist) being unfilled as of December 31, 2014.

- **Travel and Meeting Expenses** (Actual - $492K or 15% under budget) –Travel expenses were less than expected primarily due to the unfilled budgeted staff positions.

- **Other Operating Expenses** (Actual - $871K or 42% under budget) – Other operating expenses trailed budget primarily due to a reduction in the use of audit contractors as a result of the increased experience of SPP RE staff and improved performance of Registered entities.

- **SPP, Inc. Indirect Expense** (Actual - $4,173K or 14% under budget) – SPP, Inc. Indirect Expenses were less than budget due to actual FTEs being lower than budgeted FTEs and a slight decrease in the actual 2014 Overhead Rate. Indirect Expenses are discussed in greater detail below.

- **Total Expenses** (Actual $9.8 million or 17% under budget) – Although SPP RE ended the year under budget, SPP RE completed its intended activities for 2014 principally as a result of the increased experience of RE direct staff. Other contributing factors include: a higher level of Registered Entity compliance, particularly in the Operations and Planning area, which resulted in a reduced number of incoming violations; and enhanced efficiencies in internal SPP RE processes.

  Specifically, SPP RE performed 56 audits, processed 271 technical feasibility exceptions, identified 121 possible violations, processed 188 violations, reviewed 101 mitigation plans, and examined 30 reportable events. In addition, SPP RE conducted various outreach activities and published winter, summer, and long-term reliability assessments.

SPP, Inc. Shared Staff and Indirect Support Staff

The SPP governing documents, approved by NERC and FERC, allow for the use of SPP, Inc. staff not directly assigned to the SPP RE in the performance or support of some of the responsibilities that are performed by the SPP RE. There are two groups of SPP, Inc. staff that support the SPP RE. First, there is a group that performs some of the primary duties delegated to the SPP RE referred to as "shared staff." Shared staff consists of a portion of the SPP RTO engineering staff that performs the technical studies that form the basis for the SPP Regional Assessments published by NERC. Second, there is another group that supplies administrative services to the SPP RE such as accounting, computer support, human resources support, building services support, etc. referred to as "indirect support staff." In general, indirect support staff does not directly charge time and expenses to the SPP RE but are billed through an administrative charge referred to as "SPP, Inc. Indirect Overhead Expense Rate." Neither group participates in compliance or enforcement decisions of the SPP RE.

Shared staff members charge time and expenses directly to the SPP RE accounts and their hours are included in the official total full time equivalent headcount of the SPP RE for the purposes of reporting to NERC and FERC. Shared staff members record specific hours worked in the performance or support of the SPP RE's statutory functions in SPP, Inc's time tracking system. These hours are posted by the shared staff members and reviewed and approved by their specific manager or supervisor. The SPP RE Manager of Finance and Process Improvement as well as the SPP RE General Manager review the hours posted by the shared staff members. This procedure results in actual hours spent by shared staff on SPP RE statutory functions being charged directly to the particular SPP RE direct function at the shared staff member's compensation rate. These direct charges are included in the SPP RE's Business Plan and Budget. For 2014, shared staff charged 6,033 hours, or 3.2 FTEs based on SPP's standard assumption that total number of hours in a year is 1,880, to the SPP RE. 2014 budgeted shared staff FTEs were 3.75.

With respect to the costs of indirect support staff (SPP, Inc. Indirect Expenses), these costs are assessed to the SPP RE based on a fixed rate per hour per FTE. The fixed rate is calculated by

dividing the total costs for SPP, Inc. support services by the total hours worked by non-overhead personnel. The fixed rate is then multiplied by the hours charged by the shared staff and SPP RE direct staff to determine the total amount of SPP, Inc. Indirect Expenses that are assessed to the SPP RE. The SPP, Inc. Indirect Expenses assessed to the SPP RE are included in the SPP RE's Business Plan and Budget. The SPP, Inc. support costs included in the calculations are reviewed in detail to help ensure that SPP RTO specific costs are excluded from the calculation.

Due to the timing of the budget schedule, the estimated overhead rate used to develop the 2014 budget was the actual Indirect Overhead Rate for 2012, which was $75.88/hour. The actual 2014 Indirect Overhead Rate was $75.45/hour. The development of the $75.88/hour rate that was used in the development of the 2014 budget and the $75.45/hour rate embedded in the actual 2014 costs are shown in Attachments 2 and 3, respectively. Note that the Human Resources and Customer Services expenses detailed in the 2014 Budgeted Indirect Expense Rate calculation (Attachment 2) were included in the 2014 Actual Indirect Expense Rate calculation's Administration expenses (Attachment 3). In addition, the 2014 Actual Indirect Expense Rate calculation (Attachment 3) shows a one-time "IM Special Compensation" credit of $2,246k that SPP awarded employees for the successful implementation of the Integrated Marketplace on March 1, 2014. This cost was not allocated to the RE.

If you have any questions related to the submitted materials please feel free to call me at 501.688.8228 or email me at dcurrie.re@spp.org.

Sincerely,

Deborah K. Currie

Deborah K. Currie

Southwest Power Pool
Regional Entity
Statement of Activities
1/1/2014 through 12/31/2014

Total Statutory	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)
Funding			
ERO Funding			
Assessments	9,219,123	9,219,123	-
Penalty Sanctions	508,333	508,333	-
Total ERO Funding	**$ 9,727,456**	**$ 9,727,456**	**$ -**
Federal Grants	-	-	-
Membership Fees	-	-	-
Testing	-	-	-
Services & Software	-	-	-
Workshop Fees	-	-	-
Interest	2,678	-	2,678
Miscellaneous	-	-	-
Total Funding (A)	**$ 9,730,134**	**$ 9,727,456**	**$ 2,678**
Expenses			
Personnel Expenses			
Salaries	3,588,436	4,103,334	(514,898)
Payroll Taxes	224,514	313,905	(89,391)
Employee Benefits	329,902	330,805	(903)
Savings & Retirement	138,799	164,133	(25,334)
Total Personnel Expenses	**$ 4,281,651**	**$ 4,912,177**	**$ (630,527)**
Meeting Expenses			
Meetings	101,112	91,500	9,612
Travel	391,004	486,000	(94,996)
Conference Calls	-	-	-
Total Meeting Expenses	**$ 492,116**	**$ 577,500**	**$ (85,384)**
Operating Expenses			
Consultants & Contracts	706,659	1,031,000	(324,341)
Rent & Improvements	-	-	-
Office Costs	10,995	8,000	2,995
Professional Services	153,637	466,100	(312,463)
Miscellaneous	-	-	-
Depreciation	-	-	-
Total Operating Expenses	**$ 871,292**	**$ 1,505,100**	**$ (633,808)**
Total Direct Expenses	**$ 5,645,059**	**$ 6,994,777**	**$ (1,349,718)**
SPP Inc. Indirect Expenses	**$ 4,173,134**	**$ 4,828,852**	**$ (655,718)**
SPP RE Indirect Expenses [1]	**$ -**	**$ (0)**	**$ 0**
Total Indirect Expenses	**$ 4,173,134**	**$ 4,828,852**	**$ (655,718)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 9,818,193**	**$ 11,823,629**	**$ (2,005,436)**
Change in Assets (A - B)	**(88,059)**	**(2,096,173)**	**2,008,114**
Fixed Assets			
Depreciation	-	-	-
Computer & Software CapEx	-	-	-
Furniture & Fixtures CapEx	-	-	-
Equipment CapEx	-	-	-
Leasehold Improvements	-	-	-
Incr(Dec) in Fixed Assets	-	-	-
Allocation of Fixed Assets	-	-	-
Total Inc(Dec) in Fixed Assets (C)	-	-	-
TOTAL BUDGET (B + C)	**$ 9,818,193**	**$ 11,823,629**	**$ (2,005,436)**
Change in Working Capital (A-B-C)	**$ (88,059)**	**$ (2,096,173)**	**$ 2,008,114**
FTEs (2)	**29.40**	**33.85**	**(4.45)**

(1) SPP RE Indirect Expenses which represent direct expenses for SPP RE Administrative Services, are included in direct expenses.

(2) Actual FTE equal RE Direct Staff FTEs (number of days employed at RE during 2014 divided by 365) plus Shared Staff FTEs (2014 billed hours divided by 1880)

Reliability Standards

RELIABILITY STANDARDS	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	75,211	75,211	-	0.00%
Penalty Sanctions	4,119	4,119	-	0.00%
Total ERO Funding	**$ 79,330**	**$ 79,330**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ 79,330**	**$ 79,330**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	22,990	28,372	(5,382)	-18.97%
Payroll Taxes	1,353	2,170	(817)	-37.64%
Employee Benefits	2,448	2,067	381	18.44%
Savings & Retirement	879	1,135	(256)	-22.56%
Total Personnel Expenses	**$ 27,671**	**$ 33,744**	**$ (6,073)**	**-18.00%**
Meeting Expenses				
Meetings	-	-	-	
Travel	-	-	-	
Conference Calls	-	-	-	
Total Meeting Expenses	**$ -**	**$ -**	**$ -**	
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	-	-	-	
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Direct Expenses	**$ 27,671**	**$ 33,744**	**$ (6,073)**	**-18.00%**
SPP Inc. Indirect Expenses	35,462	35,664	(203)	-0.57%
SPP RE Indirect Expenses	9,467	9,922	(455)	-4.59%
Total Indirect Expenses	**$ 44,928**	**$ 45,586**	**$ (658)**	**-1.44%**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ 72,599**	**$ 79,330**	**$ (6,731)**	**-8.48%**
Change in Assets (A - B)	**$ 6,731**	**$ -**	**$ 6,731**	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B + C)	**$ 72,599**	**$ 79,330**	**$ (6,731)**	**-8.48%**
Change in Working Capital (A-B-C)	**$ 6,731**	**$ -**	**$ 6,731**	
FTE's	**0.25**	**0.25**	**-**	**0.00%**

Explanation of 2014 Variance - Reliability Standards

Expenses

- The Reliability Standards program area had no expense categories that met the criteria for a variance explanation. No variances > +/- 10% and >$10,000.

Compliance Operations, Enforcement and Organization Registration

COMPLIANCE OPERATIONS, ENFORCEMENT and ORGANIZATION REGISTRATION (Includes Critical Infrastructure Protection)	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	8,298,748	8,298,748	-	0.00%
Penalty Sanctions	364,154	364,154		0.00%
Total ERO Funding	**$ 8,662,902**	**$ 8,662,902**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ 8,662,902**	**$ 8,662,902**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	2,586,913	2,680,693	(93,780)	-3.50%
Payroll Taxes	164,689	205,073	(40,384)	-19.69%
Employee Benefits	226,169	222,723	3,446	1.55%
Savings & Retirement	102,399	107,228	(4,829)	-4.50%
Total Personnel Expenses	**$ 3,080,169**	**$ 3,215,717**	**$ (135,547)**	**-4.22%**
Meeting Expenses				
Meetings	28,426	6,500	21,926	337%
Travel	311,622	310,000	1,622	0.52%
Conference Calls	-	-	-	
Total Meeting Expenses	**$ 340,048**	**$ 316,500**	**$ 23,548**	**7.44%**
Operating Expenses				
Consultants & Contracts	675,670	726,000	(50,330)	-6.93%
Rent & Improvements		-	-	
Office Costs	8,085	-	8,085	
Professional Services		-	-	
Miscellaneous		-	-	
Depreciation		-	-	
Total Operating Expenses	**$ 683,756**	**$ 726,000**	**$ (42,244)**	**-5.82%**
Total Direct Expenses	**$ 4,103,973**	**$ 4,258,217**	**$ (154,243)**	**-3.62%**
SPP Inc. Indirect Expenses	2,917,797	3,152,662	(234,865)	-7.45%
SPP RE Indirect Expenses	1,404,020	1,252,024	151,996	12.14%
Total Indirect Expenses	**$ 4,321,817**	**$ 4,404,686**	**$ (82,869)**	**-1.88%**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ 8,425,791**	**$ 8,662,902**	**$ (237,112)**	**-2.74%**
Change in Assets (A - B)	**$ 237,112**	**$ -**	**$ 237,112**	
Fixed Assets				
Depreciation	0.00	0.00	0.00	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B + C)	**$ 8,425,791**	**$ 8,662,902**	**$ (237,112)**	**-2.74%**
Change in Working Capital (A-B-C)	**$ 237,112**	**$ -**	**$ 237,112**	
FTE's	**20.55**	**22.10**	**(1.55)**	**-7.01%**

Explanation of 2014 Variance - Compliance Operation, Enforcement and Organization Registration (Includes Critical Infrastructure Protection)

Personnel Expenses

- Payroll taxes trailed budget due to a one-time credit adjustment made for a 2013 overpayment of payroll taxes on employee's performance compensation.

Meeting Expenses

- Meeting expenses exceeded budget due to the number of meetings held with Registered Entities, particularly for CIP V5 outreach efforts.

Indirect Expenses

- SPP RE Inc. Indirect Expenses exceeded budget due to a higher percentage being allocated to this program area based on the relative share of functional program direct expenses.

Reliability Assessments and Performance Analysis

RELIABILITY ASSESSMENTS and PERFORMANCE ANALYSIS	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	2,639,558	2,639,558	-	0.00%
Penalty Sanctions	117,403	117,403	-	0.00%
Total ERO Funding	**$ 2,756,961**	**$ 2,756,961**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ 2,756,961**	**$ 2,756,961**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	409,020	835,786	(426,766)	-51.06%
Payroll Taxes	31,439	63,938	(32,498)	-50.83%
Employee Benefits	36,465	61,910	(25,444)	-41.10%
Savings & Retirement	16,439	33,431	(16,993)	-50.83%
Total Personnel Expenses	**$ 493,363**	**$ 995,065**	**$ (501,701)**	**-50.42%**
Meeting Expenses				
Meetings	622	-	622	
Travel	18,844	100,000	(81,156)	-81.16%
Conference Calls	-	-	-	
Total Meeting Expenses	**$ 19,466**	**$ 100,000**	**$ (80,534)**	**-80.53%**
Operating Expenses				
Consultants & Contracts		250,000	(250,000)	-100.00%
Rent & Improvements	-	-	-	
Office Costs		-	-	
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ -**	**$ 250,000**	**$ (250,000)**	**-100.00%**
Total Direct Expenses	**$ 512,829**	**$ 1,345,065**	**$ (832,235)**	**-61.87%**
SPP Inc. Indirect Expenses	563,838	1,016,413	(452,575)	-44.53%
SPP RE Indirect Expenses	175,445	395,483	(220,038)	-55.64%
Total Indirect Expenses	**$ 739,283**	**$ 1,411,896**	**$ (672,613)**	**-47.64%**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ 1,252,112**	**$ 2,756,961**	**$ (1,504,848)**	**-54.58%**
Change in Assets (A - B)	**$ 1,504,849**	**$ -**	**$ 1,504,848**	
Fixed Assets				
Depreciation	0.00	0.00	0.00	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B + C)	**$ 1,252,112**	**$ 2,756,961**	**$ (1,504,848)**	**-54.58%**
Change in Working Capital (A-B-C)	**$ 1,504,849**	**$ -**	**$ 1,504,848**	
FTE's	**3.98**	**7.13**	**(3.15)**	**-44.21%**

Explanation of 2014 Variance – Reliability Assessments and Performance Analysis

Personnel Expenses

- Personnel Expenses, including taxes and benefits, trailed budget primarily due to the unfilled budgeted positions. As of December 31, 2014, four positions (Director of Compliance and Events, two Lead Engineers and a CIP Compliance Specialist) were unfilled. The Director is shared between the Compliance Program and the Reliability Assessment Program. The two Engineer positions are in the Reliability Assessment program.

Meeting Expenses

- Travel Expenses trailed budget primarily due to the unfilled budgeted positions.

Operating Expenses

- Consultant and Contract Expenses trailed budget primarily due to the smooth implementation of the new BES definition; no contractual services were needed.

Indirect Expenses

- SPP Inc. Indirect Expenses trailed budget due to the actual FTEs being lower than the budgeted FTEs.

- SPP RE Inc. Indirect Expenses trailed budget due to a smaller percentage being allocated to this program area based on the relative share of functional program direct expenses.

FTEs

- FTEs were lower than budget due to the unfilled budgeted positions.

Training, Education and Operator Certification

TRAINING, EDUCATION and OPERATOR CERTIFICATION	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	258,655	258,655	-	0.00%
Penalty Sanctions	20,597	20,597		0.00%
Total ERO Funding	**$ 279,252**	**$ 279,252**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ 279,252**	**$ 279,252**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries		-	-	
Payroll Taxes		-	-	
Employee Benefits		-	-	
Savings & Retirement		-	-	
Total Personnel Expenses	**$ -**	**$ -**	**$ -**	
Meeting Expenses				
Meetings	13,304	60,000	(46,696)	-77.83%
Travel		13,000	(13,000)	-100.00%
Conference Calls	-	-	-	
Total Meeting Expenses	**$ 13,304**	**$ 73,000**	**$ (59,696)**	**-81.78%**
Operating Expenses				
Consultants & Contracts		-	-	
Rent & Improvements	-	-	-	
Office Costs	-	-	-	
Professional Services	3,769	5,000	(1,231)	-24.62%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ 3,769**	**$ 5,000**	**$ (1,231)**	**-24.62%**
Total Direct Expenses	**$ 17,073**	**$ 78,000**	**$ (60,927)**	**-78.11%**
SPP Inc. Indirect Expenses	-	178,318	(178,318)	-100.00%
SPP RE Indirect Expenses	5,841	22,934	(17,093)	-74.53%
Total Indirect Expenses	**$ 5,841**	**$ 201,252**	**$ (195,411)**	**-97.10%**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ 22,914**	**$ 279,252**	**$ (256,338)**	**-91.79%**
Change in Assets (A - B)	**$ 256,338**	**$ -**	**$ 256,338**	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B + C)	**$ 22,914**	**$ 279,252**	**$ (256,338)**	**-91.79%**
Change in Working Capital (A-B-C)	**$ 256,338**	**$ -**	**$ 256,338**	
FTE's	**-**	**1.25**	**(1.25)**	**-100.00%**

Explanation of 2014 Variance – Training, Education and Operator Certification

Meeting Expenses

- Meeting & Travel Expenses trailed budget due to the number of meetings held at the SPP Corporate Campus. Travel Expenses for the Outreach and Standards Coordinator are in the General and Administrative program area.

Indirect Expenses

- SPP Inc. Indirect Expenses trailed budget due to the actual FTEs being lower than budgeted FTEs.

- SPP RE Indirect Expenses allocated to this program area trailed budget due to a smaller percentage being allocated to this program area based on the relative share of functional program direct expenses.

FTEs

- FTEs were lower than budget due to a reassignment of personnel to other program areas.

Situation Awareness and Infrastructure Security

SITUATION AWARENESS and INFRASTRUCTURE SECURITY	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	43,124	43,124	-	0.00%
Penalty Sanctions	2,060	2,060		0.00%
Total ERO Funding	**$ 45,184**	**$ 45,184**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ 45,184**	**$ 45,184**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	17,049	18,006	(957)	-5.32%
Payroll Taxes	1,304	1,377	(73)	-5.32%
Employee Benefits	1,118	1,034	84	8.13%
Savings & Retirement	682	720	(38)	-5.32%
Total Personnel Expenses	**$ 20,152**	**$ 21,137**	**$ (985)**	**-4.66%**
Meeting Expenses				
Meetings	-	-	-	
Travel	-	-	-	
Conference Calls	-	-	-	
Total Meeting Expenses	**$ -**	**$ -**	**$ -**	
Operating Expenses				
Consultants & Contracts		-	-	
Rent & Improvements	-	-	-	
Office Costs	-	-	-	
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Direct Expenses	**$ 20,152**	**$ 21,137**	**$ (985)**	**-4.66%**
SPP Inc. Indirect Expenses	17,731	17,832	(101)	-0.57%
SPP RE Indirect Expenses	6,894	6,215	680	10.93%
Total Indirect Expenses	**$ 24,625**	**$ 24,047**	**$ 578**	**2.40%**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ 44,778**	**$ 45,184**	**$ (406)**	**-0.90%**
Change in Assets (A - B)	**$ 406**	**$ 1**	**$ 406**	
Fixed Assets				
Depreciation	0.00	0.00	0.00	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B + C)	**$ 44,778**	**$ 45,184**	**$ (406)**	**-0.90%**
Change in Working Capital (A-B-C)	**$ 406**	**$ 1**	**$ 406**	
FTE's	**0.13**	**0.13**	**-**	**0.00%**

Explanation of 2014 Variance – Situation Awareness and Infrastructure Security (SAIS)

Expenses

- The SAIS program area had no expense categories that met the criteria for a variance explanation. No variances > +/- 10% and >$10,000.

General and Administrative

GENERAL and ADMINISTRATIVE	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments	(2,096,173)	(2,096,173)	-	0.00%
Penalty Sanctions				
Total ERO Funding	**$ (2,096,173)**	**$ (2,096,173)**	**$ -**	0.00%
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ (2,096,173)**	**$ (2,096,173)**	**$ -**	**0.00%**
Expenses				
Personnel Expenses				
Salaries	552,464	540,477	11,987	2.22%
Payroll Taxes	25,728	41,346	(15,618)	-37.77%
Employee Benefits	63,702	43,072	20,630	47.90%
Savings & Retirement	18,401	21,619	(3,218)	-14.89%
Total Personnel Expenses	**$ 660,295**	**$ 646,515**	**$ 13,780**	**2.13%**
Meeting Expenses				
Meetings	58,760	25,000	33,760	135.04%
Travel	60,538	63,000	(2,462)	-3.91%
Conference Calls	-	-	-	
Total Meeting Expenses	**$ 119,298**	**$ 88,000**	**$ 31,298**	**35.57%**
Operating Expenses				
Consultants & Contracts	30,990	55,000	(24,010)	-43.65%
Rent & Improvements		-	-	
Office Costs	2,909	8,000	(5,091)	-63.64%
Professional Services	147,797	161,100	(13,303)	-8.26%
Miscellaneous		-	-	
Depreciation		-	-	
Total Operating Expenses	**$ 181,697**	**$ 224,100**	**$ (42,403)**	**-18.92%**
Total Direct Expenses	**$ 961,289**	**$ 958,615**	**$ 2,675**	**0.28%**
SPP Inc. Indirect Expenses	638,307	427,963	210,344	49.15%
SPP RE Indirect Expenses	(1,599,596)	(1,386,578)	(213,019)	15.36%
Total Indirect Expenses	**$ (961,289)**	**$ (958,615)**	**$ (2,675)**	**0.28%**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ -**	**$ -**	**$ 0**	
Change in Assets (A - B)	**$ (2,096,173)**	**$ (2,096,173)**	**$ (0)**	**0.00%**
Fixed Assets				
Depreciation	0.00	0.00	0.00	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B + C)	**$ -**	**$ -**	**$ 0**	
Change in Working Capital (A-B-C)	**$ (2,096,173)**	**$ (2,096,173)**	**$ (0)**	0.00%
FTE's	**4.50**	**3.00**	**1.50**	50.00%

Explanation of 2014 Variance – General and Administrative

Personnel Expenses

- Payroll taxes trailed budget due to a one-time credit adjustment made for a 2013 overpayment of payroll taxes on employee's performance compensation. Benefits exceeded budget primarily due to non-compensation related RE staff benefits such as the employee outing and team gifts being recorded in this expense category.

Meeting Expenses

- Meeting Expenses exceeded budget primarily due to an increase in the number of meetings held with Registered Entities.

Operating Expenses

- Consultant & Contract Expense and Professional Services trailed budget primarily due to a reduced need to engage these services.

Indirect Expenses

- SPP Inc. Indirect Expenses exceeded budget due to the actual FTEs being higher than the budgeted FTEs.

FTEs

- FTEs were higher than budget due to the reassignment of personnel to this program area.

Legal and Regulatory

LEGAL and REGULATORY	2014 Actual	2014 Budget	2014 Variance from Budget Over(Under)	
Funding				
ERO Funding				
Assessments		-	-	
Penalty Sanctions		-		
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Federal Grants	-	-	-	
Membership Fees	-	-	-	
Testing	-	-	-	
Services & Software	-	-	-	
Workshop Fees	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**-**	**-**	**-**	
Expenses				
Personnel Expenses				
Salaries	-	-	-	
Payroll Taxes	-	-	-	
Employee Benefits	-	-	-	
Savings & Retirement	-	-	-	
Total Personnel Expenses	**-**	**-**	**-**	
Meeting Expenses				
Meetings	-	-	-	
Travel	-	-	-	
Conference Calls	-	-	-	
Total Meeting Expenses	**-**	**-**	**-**	
Operating Expenses				
Consultants & Contracts	-	-	-	
Rent & Improvements	-	-	-	
Office Costs	-	-	-	
Professional Services	2,071	300,000	(297,929)	-99.31%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**2,071**	**300,000**	**(297,929)**	**-99.31%**
Total Direct Expenses	**2,071**	**300,000**	**(297,929)**	
SPP Inc. Indirect Expenses	-	-	-	
SPP RE Indirect Expenses	(2,071)	(300,000)	297,929	
Total Indirect Expenses	**$ (2,071)**	**$ (300,000)**	**$ 297,929**	**-99.31%**
Other Non-Operating Expenses	-	-	-	
Total Expenses (B)	-	-	-	
Change in Assets (A - B)	**-**	**-**	**-**	
Fixed Assets				
Depreciation	0.00	0.00	0.00	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Incr(Dec) in Fixed Assets	**-**	**-**	**-**	
Allocation of Fixed Assets	-	-	-	
Total Inc(Dec) in Fixed Assets (C)	**-**	**-**	**-**	
TOTAL BUDGET (B + C)	**-**	**-**	**-**	
Change in Working Capital (A-B-C)	**-**	**-**	**-**	
FTE's	**-**	**-**	**-**	

Explanation of 2014 Variance – Legal and Regulatory

Operating Expenses

- Professional Services cost trailed budget because SPP RE did not have any hearings in 2014.

Member Forums

Expenses

- Expenses incurred by SPP RE for forums are included in the direct expenses of the applicable program area.

Information Technology, Human Resources, and Accounting and Finance

Expenses

- Expenses incurred by SPP RE for IT, HR and Finance are accounted for within the SPP, Inc. Indirect Expense.

Attachment 2

CALCULATION OF THE SPP INC. INDIRECT EXPENSE RATE[1]

Support Groups[2]		**Overhead Costs to Allocate**	
Administration	$	15,747,334	*
Officers		6,027,900	**
Accounting		1,202,155	
SPP Compliance- Physical Security		343,273	
Human Resources		2,666,116	
Customer Services		578,985	
Legal		1,310,727	
Communications		397,133	
Information Technology		17,235,217	
Total Costs	**$**	**45,508,840**	**A**

Non-Support Resource Groups			
Ending 2012 Headcounts		319	
Average Work Hours/FTE in 2012		1880	
# of Work Hours in 2012		**599,720**	**B**
2012 Indirect Overhead Expense Rate (A/B)	**$**	**75.88**	
Times Budgeted SPP RE FTEs		**33.85**	
Times Average Work Hours/FTE		**1,880**	
Budgeted SPP Inc. Indirect Costs	**$**	**4,828,851**	

[1]Due to the timing of the budget process/schedule, the estimated overhead rate for 2014 is based on actual 2012 costs. Any variance between the estimated overhead rate and the actual 2014 overhead rate will be included in the annual 2014 Business Plan and Budget true-up filing.

[2] The services provided by these support groups are separate and distinct from the services provided by SPP RE direct staff and consultants and contractors.

* Does not include FERC Pass-Thru Fees and depreciation of market and transmission assets.

** Does not include costs for executives performing delegated functions.

Attachment 3

CALCULATION OF THE SPP INC. ACTUAL INDIRECT EXPENSE RATE

Support Groups[1]		**Overhead Costs to Allocate**	
Administration	$	19,188,632	*
Officers		6,495,908	**
Accounting		1,326,296	
Corporate Services		5,220,237	
Compliance		-	
Internal Audit		-	
Reliability Standards		-	
Project Management		-	
Process Management		-	
Legal		1,525,595	
Communications		406,236	
Information Technology		15,883,675	
Less: IM Special Comp		(2,245,579)	
Total Costs	**$**	**47,801,000**	**A**

Non-Support Resource Groups			
Ending 2014 Headcounts		337	
Average Work Hours/FTE in 2014		1880	
# of Work Hours in 2014		**633,560**	**B**
2014 Indirect Overhead Expense Rate (A/B)	**$**	**75.45 (75.44826)**	
Times ACTUAL SPP RE FTEs		**29.4 (29.42085)**	
Times Average Work Hours/FTE		**1,880**	
Actual SPP Inc. Indirect Costs	**$**	**4,173,134**	

[1] The services provided by these support groups are separate and distinct from the services provided by SPP RE direct staff and consultants and contractors.

* Does not include FERC Pass-Thru Fees and depreciation of market and transmission assets.
** Does not include costs for executives performing delegated functions.

Southwest Power Pool, Inc.

Independent Auditor's Report and Financial Statements

December 31, 2014 and 2013

BKD LLP
CPAs & Advisors

Southwest Power Pool, Inc.

December 31, 2014 and 2013

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BKD LLP
CPAs & Advisors

400 W. Capitol Avenue, Suite 2500 // P.O. Box 3667 // Little Rock, AR 72203-3667
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Independent Auditor's Report

Board of Directors
Southwest Power Pool, Inc.
Little Rock, Arkansas

We have audited the accompanying financial statements of Southwest Power Pool, Inc., which comprise the balance sheets as of December 31, 2014 and 2013, and the related statements of operations, changes in members' deficit and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Praxity
MEMBER
GLOBAL ALLIANCE OF INDEPENDENT FIRMS

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Southwest Power Pool, Inc. as of December 31, 2014 and 2013, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in *Note 2* to the financial statements, the 2013 financial statements have been restated to correct a misstatement. Our opinion is not modified with respect to this matter.

BKD, LLP

Little Rock, Arkansas
April 13, 2015

Southwest Power Pool, Inc.

Balance Sheets

(*in Thousands*)

December 31, 2014 and 2013

Assets

	2014	2013 (Restated – Note 2)
Current Assets		
Cash and cash equivalents	$ 57,534	$ 35,262
Restricted cash deposits	222,285	76,713
Accounts receivable	41,826	24,134
Prepaid expenses and other	7,204	6,977
Total current assets	328,849	143,086
Property and Equipment, at Cost		
Land	4,812	4,812
Building	66,354	66,225
Furniture and fixtures	10,016	10,026
Equipment and machinery	44,822	41,647
Software	206,237	93,720
Software in development	12,458	106,895
	344,699	323,325
Less accumulated depreciation and amortization	167,818	119,065
	176,881	204,260
Investments (*Note 3*)	10,099	9,258
Other Assets, Net	5,184	2,802
	$ 521,013	$ 359,406

See Notes to Financial Statements

Liabilities and Members' Deficit

	2014	2013 (Restated – Note 2)
Current Liabilities		
Accounts payable	$ 31,417	$ 15,953
Customer deposits	222,285	76,713
Current maturities of long-term debt (*Note 5*)	24,299	22,998
Accrued expenses	57,943	29,039
Deferred revenue	5,895	5,919
Total current liabilities	341,839	150,622
Long-term Debt (*Note 5*)	247,961	235,260
Other Long-term Liabilities	18,159	14,420
Members' Deficit	(86,946)	(40,896)
	$ 521,013	$ 359,406

Southwest Power Pool, Inc.

Statements of Operations

(*in Thousands*)

Years Ended December 31, 2014 and 2013

	2014	2013 (Restated – Note 2)
Operating Income		
Tariff fees and member assessments	$ 158,735	$ 137,811
Other member services	4,802	4,926
	163,537	142,737
Operating Expenses		
Salaries and benefits	85,575	80,615
Employee travel	1,924	1,868
Administrative	4,399	3,967
Regulatory assessment	16,323	14,699
Meetings	833	930
Communications system	3,745	3,666
Leases	180	432
Maintenance	15,149	11,300
Consulting services	16,319	16,114
Depreciation and amortization	51,046	19,398
	195,493	152,989
Operating Loss	(31,956)	(10,252)
Other Income (Expense)		
Investment income	459	731
Interest expense	(12,554)	(7,763)
Change in fair market value of interest rate swaps	(1,528)	923
Other income	75	258
	(13,548)	(5,851)
Loss Before Unrealized Gain and Change in Funded Status of Employee Benefit Plans	(45,504)	(16,103)
Unrealized Gain on Investments	251	710
Change in Funded Status of Employee Benefit Plans	(797)	5,225
Net Loss	$ (46,050)	$ (10,168)

See Notes to Financial Statements

Southwest Power Pool, Inc.

Statements of Members' Deficit

(*in Thousands*)

Years Ended December 31, 2014 and 2013

	2014	2013
Balance, Beginning of Year	$ (40,896)	$ (30,728)
Net loss	(46,050)	(10,168)
Balance, End of Year	$ (86,946)	$ (40,896)

Southwest Power Pool, Inc.

Statements of Cash Flows

(*in Thousands*)

Years Ended December 31, 2014 and 2013

	2014	2013 (Restated – Note 2)
Operating Activities		
Net loss	$ (46,050)	$ (10,168)
Items not requiring cash		
Depreciation and amortization	51,046	19,398
Change in funded status of employee benefit plans	797	(5,225)
Unrealized gain on investments	(251)	(710)
Realized gain on investments	-	(157)
(Gain)/loss on disposal of fixed assets	(23)	2
Change in fair market value of interest rate swaps	1,528	(923)
Changes in assets and liabilities		
Accounts receivable	(17,692)	(6,211)
Prepaid expenses and other	(227)	(1,560)
Other assets	(2,472)	(674)
Accounts payable	15,464	6,122
Accrued expenses	28,880	(70)
Other long-term liabilities	1,414	2,696
Net cash provided by operating activities	32,414	2,520
Investing Activities		
Acquisition of property and equipment	(23,554)	(49,818)
Purchase of investments	(590)	(1,657)
Proceeds from sale of investments	-	766
Net cash used in investing activities	(24,144)	(50,709)
Financing Activities		
Repayments of long-term debt	(22,998)	(12,700)
Issuance of long-term debt	37,000	-
Net cash provided by (used in) financing activities	14,002	(12,700)
Increase/(Decrease) in Cash and Cash Equivalents	22,272	(60,889)
Cash and Cash Equivalents, Beginning of Year	35,262	96,151
Cash and Cash Equivalents, End of Year	$ 57,534	$ 35,262
Supplemental Cash Flow Information		
Interest paid on long-term debt (net of interest capitalized of $363 and $2,777 in 2014 and 2013, respectively)	$ 10,576	$ 7,932

Southwest Power Pool, Inc.

Notes to Financial Statements

(*in Thousands*)

December 31, 2014 and 2013

Note 1: Nature of Operations and Summary of Significant Accounting Policies

Nature of Operations

Southwest Power Pool, Inc. (the Company) is a not-for-profit entity formed in 1941 and incorporated in 1994. The Company is a Federal Energy Regulatory Commission (FERC)-approved regional transmission organization (RTO) serving more than six million ultimate customers across all or parts of nine states. The Company's membership consists of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, contract participants, power marketers and independent transmission companies.

Major services provided by the Company to its members and customers include tariff administration, electric reliability coordination, regional transmission scheduling, energy imbalance service (EIS) market operations and regional transmission expansion planning. Effective March 1, 2014, the EIS market was replaced with Integrated Marketplace which includes day-ahead and real time markets, transmission congestion rights, reliability unit commitment, operating reserve market, and consolidated balancing authority.

The Company also serves as the Regional Entity (RE) for its region. The primary responsibility of the RE is the enforcement of North American Electric Reliability Corporation (NERC)-approved reliability standards for users, owners and operators of the bulk power system within the region.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents and Deposits

The Company considers all highly liquid interest-earning investments with stated maturities and coupon rate reset dates of no more than three months to be cash equivalents. At December 31, 2014 and 2013, the Company's cash and cash equivalents, including restricted deposits, are invested primarily in money market funds, mutual funds and repurchase agreements. These investments are typically revalued to the market each day and, in the case of repurchase agreements, are collateralized by U.S. government and federal agency securities. The Company's cash and cash equivalents consist primarily of funds accumulated for general operating purposes. Restricted cash deposits consist primarily of customer security deposits, amounts deposited for engineering studies and funds held in escrow for disputed invoices.

Investments

The Company's investments include domestic and foreign issued stock and equity and fixed income mutual funds. These investments are recorded at fair value, with unrealized gains and losses reported as non-operating income. Dividends, interest income, and realized gains and losses are reported as investment income. The Company's investments are intended to be utilized in funding benefits associated with the Company's postretirement health care plan.

Income Taxes

The Company is exempt from income taxes under Section 501c(6) of the Internal Revenue Code and a similar provision of state law. However, the Company is subject to federal income tax on any unrelated business taxable income.

The Company files tax returns in the U.S. federal jurisdiction. With a few exceptions, the Company is no longer subject to U.S. federal examinations by tax authorities for years before 2011.

Accounts Receivable

Accounts receivable are stated at the amount billed to members, customers and others plus any accrued and unpaid interest. The Company provides an allowance for doubtful accounts, when necessary, which is based upon a review of outstanding receivables, historical collection information and existing economic conditions. Accounts that are unpaid after the due date are subject to interest at a rate set by FERC. No allowance for doubtful accounts has been recorded for 2014 and 2013.

Property and Equipment

Property and equipment are recorded at cost and depreciated on a straight-line basis over the estimated useful life of each asset. The estimated useful lives are as follows:

Building	20 years
Building improvements	Shorter of useful life or remaining life of building
Furniture and fixtures	5 years
Vehicles	5 years
Equipment and machinery	3 years
Software	3 years

The Company capitalizes interest cost incurred on funds used to construct property, plant and equipment. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life. Interest cost capitalized was $363 and $2,777 in 2014 and 2013, respectively.

The Company capitalizes development costs, including interest, for internal use software costs. These costs are included in software in development. Management of the Company is of the opinion that all costs capitalized in association with the software in development are fully recoverable over the anticipated life of the asset.

Long-lived Asset Impairment

The Company evaluates the recoverability of the carrying value of long-lived assets whenever events or circumstances indicate the carrying amount may not be recoverable. If a long-lived asset is tested for recoverability and the undiscounted estimated future cash flows expected to result from the use and eventual disposition of the asset is less than the carrying amount of the asset, the asset cost is adjusted to fair value and an impairment loss is recognized as the amount by which the carrying amount of a long-lived asset exceeds it fair value.

No asset impairment was recognized during the years ended December 31, 2014 and 2013.

Revenue Recognition

Revenues, consisting of member assessments, tariff administrative fees, contract services and miscellaneous revenues are recognized when earned, and expenses are recognized when incurred.

Customer Deposits

Customers may be required to make deposits with the Company prior to the performance of transmission services and engineering studies. These amounts are typically held for the duration of the service and applied to the customer's final invoice. An offsetting liability equal to the deposit balance is recorded in current liabilities. Funds held in escrow related to disputed invoices are also recorded as a customer deposit under current liabilities.

Tariff Fees and Member Assessments

An administrative charge is applied to all transmission service under the Company's tariff to cover the expenses related to the administration of the tariff. The charge is calculated in accordance with the terms of the Company's Open Access Transmission Tariff. The administrative rate used for the calculation is established by the board of directors.

Members are assessed monthly based on their prior year average 12-month peak demand multiplied by the total hours in a month and by the monthly assessment rate as established by the board. A member's monthly assessment is offset dollar for dollar for qualifying tariff administrative fees collected from a member in any given assessment period.

The Company collects a membership fee from each member annually. The amount of the membership fee is established by the board of directors of the Company. For 2014 and 2013, all members paid a $6 membership fee.

The Company also bills transmission customers and transmission owners a charge under Schedule 12 on all energy delivered under point-to-point transmission service and network integration transmission service. This provides a mechanism for recovering from transmission customers and transmission owners the annual charges the Company pays to FERC. The rate is developed by FERC in the prior calendar year and applied to energy transmitted in the second prior calendar year.

Deferred Revenue

Revenues for contract services received in advance are recognized over the periods to which the revenues relate.

Other Member Services

The Company provides reliability, tariff administration and scheduling for non-members on a contract basis. The Company also provides engineering study services for long-term transmission service and generation interconnection studies.

Withdrawing Members

Members wishing to withdraw their membership from the Company must provide 24 months written notice and are responsible for their portion of the Company's existing obligations as defined in the bylaws, which include unpaid membership fees, any assessments imposed prior to the effective withdrawal date, any costs or expenses imposed upon the Company as a direct consequence of the member's withdrawal, and the member's share of long-term obligations and related interest. Withdrawing members may also be responsible for all financial obligations incurred and costs allocated to its load for transmission facilities approved prior to their withdrawal.

Concentration of Credit Risk

The Company is exposed to credit risk primarily through accounts receivable and uninsured cash balances. During 2014 and 2013, the Company maintained cash balances, including transaction accounts and short-term investment accounts that are not insured by the Federal Deposit Insurance Corporation. The Company did not have transaction accounts exceeding federal insurance limits at December 31, 2014. The Company's transaction accounts exceeded federal limits by $9,758 at December 31, 2013. The Company's investment accounts were primarily invested in highly liquid short-term investments such as money market funds, mutual funds and repurchase agreements. The Company also requires the financial institutions holding its cash balances to be rated A or better by nationally recognized rating agencies.

Because the Company considers all accounts receivable to be highly probable of collection, an allowance for doubtful accounts is currently not maintained. The Company requires its customers to meet certain minimum standards of financial condition and creditworthiness to receive unsecured credit from the Company. If these standards cannot be met by a counterparty, the Company requires the posting of defined financial security instruments to cover potential liabilities.

Reclassifications

Certain reclassifications have been made to the 2013 financial statements to conform to the 2014 financial statement presentation. These reclassifications had no effect on net earnings.

Southwest Power Pool, Inc.

Notes to Financial Statements

(*in Thousands*)

December 31, 2014 and 2013

Note 2: Restatement of Prior Years' Financial Statements

In 2014, the Company corrected an error in presenting its Post-retirement Healthcare Plan. The assets intended to fund the benefits are held in an agency account at a trust company and not in a formally established trust. The impacts of this correction are: 1) the assets could no longer be considered plan assets for financial reporting purposes, 2) the return on these assets could no longer be factored into the calculation of the actuarially computed pension cost, and 3) the earnings and related expenses associated with the agency assets must be recorded in the statement of operations.

Based on this correction, assets and liabilities of the Company's noncontributory defined benefit postretirement health care plan as of December 31, 2014 are recorded on a gross basis as long term assets and liabilities, respectively. The Company previously reported these assets and liabilities on a net basis. Reclassification of the balances as of December 31, 2013 to conform to the 2014 presentation had no impact on equity.

Earnings and related expenses associated with the agency assets are reflected in the statement of operations for the year ended December 31, 2014. The addition of the incremental benefit cost and earnings and expenses of the agency assets for the year ended December 31, 2013 resulted in an offsetting adjustment to the change in funded status of employee benefit plans with no impact to net loss previously reported.

	As Restated	As Previously Reported	Effect of Change
Balance Sheet			
Cash	$ 35,262	$ 34,874	$ 388
Prepaid expenses and other	6,977	6,967	10
Investments	9,258	-	9,258
Other assets	2,802	4,463	(1,661)
Total assets	359,406	351,411	7,995
Other long-term liabilities	14,420	6,425	7,995
Statement of Operations			
Salaries and benefits	80,615	79,661	954
Consulting services	16,114	16,077	37
Investment income	731	223	508
Unrealized gains	710	-	710
Change in funded status of employee benefit plans	5,225	5,452	(227)
Statement of Cash Flows			
Cash flow provided by operations	2,520	1,699	821
Cash used in investing activities	50,709	49,818	891
Beginning cash balance	96,151	95,693	458
Ending cash balance	35,262	34,874	388

Note 3: Investment and Investment Returns

Investments at December 31 consisted of the following:

	2014	2013 (Restated – Note 2)
Mutual Funds		
Equity	$ 3,186	$ 3,149
Fixed Income	2,732	2,282
Financials	610	498
Alternative Assets	271	333
Total Mutual Funds	6,799	6,262
Domestic Common Stock		
Consumer discretionary	417	365
Consumer staples	393	351
Energy	229	260
Financial	452	405
Health care	456	384
Industrials	404	385
Information technology	574	512
Materials	172	163
Telecommunication	37	39
Utilities	125	94
Total Common Stock	3,259	2,959
Foreign Stocks		
Industrials	41	38
	$ 10,099	$ 9,258

Total investment return is comprised of the following:

	2014	2013 (Restated – Note 2)
Interest and dividends reported at fair value	$ 242	$ 204
Net realized and unrealized gains on investments reported at fair value	468	1,013
	$ 710	$ 1,217

Interest, dividends, and realized gains are reported as investment income while unrealized gains are reported separately in the statement of operations.

Note 4: Line of Credit

The Company has a $30,000 revolving line of credit expiring in 2016. At December 31, 2014 and 2013, no amounts were borrowed against this line. The agreement has a variable interest rate equal to the London Interbank Offered Rate (LIBOR) plus a credit margin. The Company's line of credit requires compliance with certain financial and non-financial covenants as well as periodic reporting requirements. The Company was in compliance with the covenant and reporting requirements throughout and at December 31, 2014.

Note 5: Long-term Debt and Interest Rate Swaps

Long-term Debt

	2014	2013
Variable Rate Term Note due 2027 (A)	$ 3,547	$ 3,752
Variable Rate Term Note due 2014 (B)	—	5,500
5.45% Senior Notes due 2016 (C)	9,000	15,000
4.82% Series 2010-A Senior Notes due 2042 (D)	29,060	29,541
4.82% Series 2010-B Senior Notes due 2042 (E)	33,903	34,465
3.55% Series 2010-C Senior Notes due 2024 (F)	64,750	70,000
3.00% Series 2012-D-1 Senior Notes due 2024 (G)	46,250	50,000
3.25% Series 2012-D-2 Senior Notes due 2024 (H)	48,750	50,000
3.80% Series 2014-E Senior Notes Due 2025 (I)	37,000	—
	272,260	258,258
Less current maturities	24,299	22,998
	$ 247,961	$ 235,260

(A) Due February 1, 2027; principal and interest are payable quarterly based on a 25-year amortization. Payments commenced on May 1, 2007. The interest rate adjusts monthly based on the London Interbank Offered Rate (LIBOR) plus 0.85%. The note is secured by a first mortgage on the Company's operation facility.

(B) Due December 25, 2014; interest is payable monthly and principal is payable quarterly based on a seven-year amortization. Payments commenced on March 25, 2008. The interest rate adjusts monthly based on the LIBOR plus 0.30%. The note is unsecured.

(C) Due July 23, 2016; principal and interest are payable quarterly based on a seven-year amortization. Payments commenced on September 30, 2011. The interest rate is fixed at 5.45%. The note is unsecured.

(D) Due December 30, 2042; principal and interest are payable quarterly based on a 32-year amortization. Principal payments commenced on March 30, 2013. The interest rate is fixed at 4.82%. The note is unsecured.

(E) Due December 30, 2042; principal and interest are payable quarterly based on a 32-year amortization. Principal payments commenced on March 30, 2013. The interest rate is fixed at 4.82%. The note is unsecured.

(F) Due March 30, 2024; principal and interest are payable quarterly based on 13-year amortization. Principal payments commenced on June 30, 2014. The interest rate is fixed at 3.55%. The note is unsecured.

(G) Due March 30, 2024; principal and interest are payable quarterly based on 10-year amortization. Principal payments commenced on June 30, 2014. The interest rate is fixed at 3.00%. The note is unsecured.

(H) Due September 30, 2024; principal and interest are payable quarterly based on 10-year amortization. Principal payments commenced on December 30, 2014. The interest rate is fixed at 3.25%. The note is unsecured.

(I) Due December 30, 2025; principal and interest are payable quarterly based on an 11 year and 9 months amortization. Principal payments commence on March 30, 2024. The interest rate is 3.80%. The note is unsecured.

Aggregate annual maturities of long term debt at December 31, 2014, are:

2015	$ 24,299
2016	23,603
2017	21,409
2018	21,469
2019	22,281
Thereafter	159,199
	$ 272,260

On March 10, 2014, the Company obtained a $33,000 senior unsecured term note facility. This facility remains undrawn at December 31, 2014, but allows the Company to obtain advances as needed during a two year draw period, after which it will convert into an amortizing term loan with escalating principal payments through 2024. Interest will be payable monthly at LIBOR plus 1.75%.

Certain of the Company's term notes require compliance with financial and non-financial covenants, as well as periodic reporting requirements. The Company was in compliance with the covenant and reporting requirements throughout and at December 31, 2014.

Variable-to-Fixed Interest Rate Swap

As a strategy to maintain acceptable levels of exposure to the risk of changes in future cash flows due to interest rate fluctuations, the Company enters into interest rate swap agreements.

On September 15, 2006, the Company entered into an interest rate swap agreement with U.S. Bank National Association. The agreement provides for the Company to receive interest from the counterparty at LIBOR and to pay interest to the counterparty at a fixed rate of 5.51% on notional amounts of $3,519 and $3,723 at December 31, 2014 and 2013, respectively. Under the agreement, the Company pays or receives the net interest amount quarterly, with the quarterly settlements included in interest expense. The swap was established to hedge interest rate risk on its floating rate debt obligation (Loan A).

The Company entered into another interest rate swap agreement on August 23, 2007, with U.S. Bank National Association. The agreement provided for the Company to receive interest from the counterparty at LIBOR and to pay interest to the counterparty at a fixed rate of 5.31% on notional amounts of $5,500 at December 31,2013. This swap matured December 25, 2014. Under the agreement, the Company paid or received the net interest amount monthly, with the monthly settlements included in interest expense. The swap was established to hedge interest rate risk on its floating rate debt obligation (Loan B).

The Company entered into another interest rate swap agreement on March 10, 2014, with Regions Bank. The agreement provides for the Company to receive interest from the counterparty at LIBOR and to pay interest to the counterparty at a fixed rate of 3.225% on notional amounts of $33,000. Under the agreement, the Company pays or receives the net interest amount monthly, commencing on March 30, 2016, with the monthly settlements included in interest expense. The swap was established to hedge interest rate risk on its floating rate debt obligation associated with the $33,000 note that remains undrawn at December 31, 2014.

The table below presents certain information regarding the Company's interest rate swap agreements.

	2014	2013
Fair value of interest rate swap agreements	$ 2,462	$ 934
Balance sheet location of fair value amounts	Other Long-term Liabilities	Other Long-term Liabilities
Gain/(loss) recognized in statement of operations	$ (1,528)	$ 923
Location of gain recognized in statement of operations	Change in Fair Market Value of Interest Rate Swaps	Change in Fair Market Value of Interest Rate Swaps

Note 6: Operating Leases

The Company has noncancellable operating leases for certain office equipment which expire on June 30, 2015. The lease for office space expired in early 2013. The Company incurred lease expense related to these operating leases of $180 and $432 in 2014 and 2013, respectively. Future minimum lease payments at December 31, 2014, were $69 for contracts expiring in 2015.

Note 7: Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

The Company has a noncontributory defined benefit pension plan covering all employees meeting eligibility requirements. The Company's funding policy is to make the minimum annual contribution that is required by applicable regulations, plus such amounts as the Company may determine to be appropriate from time to time. The Company expects to contribute approximately $3,760 to the plan in 2015.

The Company has a noncontributory defined benefit postretirement health care plan covering eligible retirees, including those retiring between the ages of 55–65 and hired prior to January 1, 1996. Employees hired after June 1, 2006, are not eligible to participate in the defined postretirement health care plan.

The Company uses a December 31 measurement date for the plans. Information about the plans' funded status is as follows:

	Pension Benefits		Postretirement Health Care Benefits	
	2014	2013	2014	2013 (Restated – Note 2)
Benefit obligation	$ 50,702	$ 44,090	$ 8,900	$ 7,995
Fair value of plan assets	45,903	41,157	—	—
Funded status	$ (4,799)	$ (2,933)	$ (8,900)	$ (7,995)

Amounts recognized in the balance sheets:

	Pension Benefits		Postretirement Health Care Benefits	
	2014	2013	2014	2013 (Restated – Note 2)
Noncurrent assets	$ —	$ —	$ —	$ —
Noncurrent liabilities	(4,799)	(2,933)	(8,900)	(7,995)
	$ (4,799)	$ (2,933)	$ (8,900)	$ (7,995)

Amounts recognized in members' equity not yet recognized as components of net periodic benefit cost as of December 31, 2014, consist of:

	Pension Benefits	Postretirement Health Care Benefits
Net loss	$ 6,746	$ 6,113
Prior service credit	(22)	—
Transition obligation	99	26
	$ 6,823	$ 6,139

The accumulated benefit obligation for the defined benefit pension plan was $40,001 and $34,673 at December 31, 2014 and 2013, respectively.

Other significant balances and costs are:

	Pension Benefits		Postretirement Health Care Benefits	
	2014	2013	2014	2013
Employer contributions	$ 3,660	$ 4,010	$ 441	$ 540
Benefits paid	433	256	83	35
Benefit costs	4,199	4,625	1,435	1,466

Contributions to the postretirement health care plan represent funding to the agency account holding assets intended to be utilized in providing benefits for eligible retirees.

The following amounts have been recognized in the statements of operations for the year ended December 31, 2014:

	Pension Benefits	Postretirement Health Care Benefits
Amounts arising during the period		
Net gain/(loss)	$ (1,403)	$ 143
Amounts recognized as components of net periodic benefit cost of the period		
Net loss	58	303
Net prior service credit	1	—
Net transition obligation	16	4

The estimated net loss, prior service cost and transition obligation for the defined benefit pension plan that will be amortized from members' equity into net period benefit cost over the next fiscal year are $105, $1 and $16, respectively. The estimated net gain, prior service cost, and net obligation for the defined benefit postretirement health care plan that will be amortized from members' equity into net periodic benefit cost over the next fiscal year are $275, $0, and $4, respectively.

Weighted-average assumptions used to determine benefit obligations and costs:

	Pension Benefits		Postretirement Health Care Benefits	
	2014	2013	2014	2013
Discount rate benefit obligation	5.5%	5.5%	5.5%	5.5%
Expected return on plan assets	7.0%	7.0%	—	—
Rate of compensation increase	4.0%	4.0%	—	—

The Company has estimated the long-term rate of return on plan assets based primarily on historical returns on plan assets, adjusted for changes in target portfolio allocations and recent changes in long-term interest rates based on publicly available information.

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014 and 2013. The rate was assumed to decrease gradually to 5% by the year 2020 and remain at that level thereafter.

On December 8, 2003, the *Medicare Prescription Drug, Improvement and Modernization Act of 2003* (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide benefits at least actuarially equivalent to Medicare Part D. The Company has not determined whether its plan provides benefits that are actuarially equivalent to Medicare Part D.

Financial Accounting Standards Board Staff Position 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*, subsequently incorporated into FASB Accounting Standards Codification (ASC) 715-60, requires federal subsidies, if any, attributable to past service to be accounted for as an actuarial gain and federal subsidies, if any, attributable to current service to be accounted for as a reduction of net periodic benefit cost. The measures of projected benefit obligation and periodic benefit costs do not reflect any amounts associated with the subsidy because the Company has been unable to conclude whether the benefits provided by the plan are actuarially equivalent to Medicare Part D. The effect of adopting the provisions of ASC 715-60, if and when the Company makes such a determination, is not expected to be material.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid as of December 31:

	Pension Benefits	Postretirement Health Care Benefits
2015	$ 628	$ 117
2016	732	155
2017	839	191
2018	1,041	244
2019	1,224	287
2020–2024	9,859	2,040

The Company's investment strategy is based on an expectation that equity securities will outperform fixed income securities over the long-term. Accordingly, the composition of the Company's plan assets is broadly characterized as a 70/30 allocation between equity and fixed income securities. The strategy utilizes indexed and actively managed mutual fund instruments as well as direct investment in individual equity and fixed income securities. Investments in the plan must adhere to the Investment Policy Statement developed by the Company. The Investment Policy Statement limits investments in foreign securities to 20% of the total fair value of plan assets. The Investment Policy Statement is reviewed annually. At December 31, 2014 and 2013, plan assets by category are as follows:

	Pension Plan Assets	
	2014	2013
Fixed income securities	23%	17%
Equity securities	72	76
Cash and equivalents	5	7
	100%	100%

Pension Plan Assets

Following is a description of the valuation methodologies used for the pension plan assets measured at fair value on a recurring basis and recognized in the accompanying balance sheets, as well as the general classification of the assets pursuant to the valuation hierarchy.

Where quoted market prices are available in an active market, plan assets are classified within Level 1 of the valuation hierarchy. Level 1 plan assets include cash, money market accounts, closed- end mutual funds and common and foreign company stock. If quoted market prices are not available, then fair values are estimated by using pricing models, quoted prices of plan assets with similar characteristics or discounted cash flows. Level 2 plan assets include open-end mutual funds, corporate debt obligations, foreign corporate debt obligations, government securities and foreign government securities.

In certain cases where Level 1 or Level 2 inputs are not available, plan assets are classified within Level 3 of the hierarchy. At December 31, 2014 and 2013, the Company does not hold any plan assets valued using Level 3 inputs.

The fair values of the Company's pension plan assets at December 31, 2014, by asset category are as follows:

		Fair Value Measurements Using		
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash Equivalents	$ 1	$ 1	$ -	$ -
Money Market Mutual Funds	2,356	2,356	-	-
Mutual Funds				
Alternative Assets	596	-	596	-
Equity Funds	23,118	16,029	7,089	-
Fixed Income Funds	3,584	2,069	1,515	-
	27,298	18,098	9,200	-
Domestic Common Stock				
Consumer Discretionary	68	68	-	-
Energy	4,269	4,269	-	-
Financials	1,376	1,376	-	-
Healthcare	2,068	2,068	-	-
Industrials	432	432	-	-
Materials	624	624	-	-
Telecommunication Services	613	613	-	-
	9,450	9,450	-	-
Foreign Stocks				
Energy	407	407	-	-
Materials	285	285	-	-
	692	692	-	-
Corporate Debt Obligations	4,734	-	4,734	-
Foreign Debt Obligations	774	-	774	-
Foreign Government Securities	598	-	598	-
Total	$ 45,903	$ 30,597	$ 15,306	$ 0

The fair values of the Company's pension plan assets at December 31, 2013, by asset category are as follows:

		Fair Value Measurements Using		
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash Equivalents	$ 5	$ 5	$ -	$ -
Money Market Mutual Funds	875	875	-	-
Mutual Funds				
Advantage Equity Funds	2,627	-	2,627	-
Equity Funds Small Cap	1,780	-	1,780	-
Equity Funds Mid Cap	3,172	-	3,172	-
Equity Funds Large Cap	8,813	-	8,813	-
International Funds	996	-	996	-
	17,388	-	17,388	-
Domestic Common Stock				
Consumer Discretionary	109	109	-	-
Energy	3,185	3,185	-	-
Financial	1,136	1,136	-	-
Healthcare	2,297	2,297	-	-
Industrials	518	518	-	-
Materials	867	867	-	-
Telecommunication	1,124	1,124	-	-
	9,236	9,236	-	-
Foreign Common Stocks				
Energy	1,685	1,685	-	-
Financial	1,136	1,136	-	-
Healthcare	327	327	-	-
Industrials	124	124	-	-
Materials	1,331	1,331	-	-
Telecommunication	175	175	-	-
	4,778	4,778	-	-
Corporate Debt Obligations	5,298	-	5,298	-
Foreign Debt Obligations	930	-	930	-
U. S. Government Securities	2,000	-	2,000	-
Foreign Government Securities	647	-	647	-
Total	$ 41,157	$ 14,894	$ 26,263	$ 0

Defined Contribution Plans

The Company has a 401(k) defined contribution plan covering substantially all employees. The Company contributes funds to the plan on behalf of plan participants equal to 75% of the participants' elective deferrals up to 6% of deferred compensation. Contributions to the plan were $2,466 and $2,334 for 2014 and 2013, respectively.

The Company has a 457(b) non-qualified tax-deferred compensation plan. This plan is an unfunded plan maintained for the purpose of providing deferred compensation for a select group of management or highly-compensated employees and, therefore, is intended to be exempt from the participation, vesting, funding and fiduciary requirements of Title I of the *Employee Retirement Income Security Act of 1974* (ERISA). Accumulated contributions and earnings of $1,584 and $1,305 are recorded in other long-term liabilities at December 31, 2014 and 2013, respectively. The Company also offered a 457(f) non-qualified tax-deferred compensation plan to a select group of executive management. The 457(f) plan was intended to be exempt from the participation, vesting, funding and fiduciary requirements of Title I of ERISA and serves to further supplement benefits lost due to IRS limits on compensation and benefits. All accrued benefits associated with this plan were paid out in 2014. There were accrued benefits of $1,253 recorded in other long-term liabilities for the 457(f) plan participants at December 31, 2013.

Note 8: Related Party Transactions

General disbursements of the Company are apportioned to members based on the formula described in the bylaws of the Company (see *Note 1*). The Company's receivables from members totaled $31,590 and $17,571 as of December 31, 2014 and 2013, respectively. The Company recognized revenues of $149,170 and $128,486, including assessments and tariff administrative fees, from members for the years ended December 31, 2014 and 2013, respectively.

The Southwest Power Pool Regional State Committee (RSC) was incorporated on April 7, 2004, in the State of Arkansas. The RSC is comprised of commissioners from public service commissions or equivalent, having regulatory authority over Company members. FERC, in its February 20, 2004, order regarding the Company's RTO application, stated, "the RSC should have primary responsibility for determining regional proposals and the transition process for funding of regional transmission enhancements, rate structure for a regional access charge and allocation of transmission rights." The RSC prepares budgets annually for the expected costs of its operations. This budget is submitted to the Company's board of directors for approval. The Company includes in its annual budget funds sufficient to cover 100% of the operating costs of the RSC. During 2014 and 2013, the Company incurred $248 and $226, respectively, in expenses attributable to RSC operations. Management of the Company expects such expenditures for 2015 to be approximately $338.

Note 9: Open Access Transmission and Market Operations

The Company provides short- and long-term firm and non-firm point-to-point transmission services and network integration transmission service across 29 providers in nine states. The Company is responsible for the billing of the transmission customers for the respective services and the remittance of the subsequent collections to the transmission owner on a monthly basis. Billings for these transmission services are not included in the statements of operations. The Company receives a fee for facilitating the transmission process, which is recorded as tariff fees in the Company's statements of operations. For the years ended December 31, 2014 and 2013, the Company billed transmission customers $1,505,561 and $1,290,757, respectively. For the years ended December 31, 2014 and 2013, the Company remitted to transmission owners $1,358,434 and $1,171,133 respectively. At December 31, 2014 and 2013, the Company was due to collect from customers and remit to owners transmission service charges of $110,019 and $101,106, respectively.

In March 2014, the Company launched the Integrated Marketplace which includes a day-ahead market with transmission congestion rights, a reliability unit commitment process, a real-time balancing market replacing the EIS market, an operating reserve market, and a consolidated balancing authority. Weekly settlements of market participants' energy transactions are not reflected in the Company's statements of operations since they do not represent revenues or expenses of the Company, as the Company merely acts as an intermediary in the settlement process. In this role, the Company receives and disburses funds to/from market participants on a weekly basis. At December 31, 2014, the Company held $28,102 in cash collections from the settlement of auction revenue rights in accordance with terms of the Company's tariff. These funds will be disbursed annually in June for collections from the previous twelve months. A corresponding liability is reflected in accrued expenses on the balance sheet.

Note 10: Commitments and Contingencies

Litigation and Regulatory Matters

The Company is engaged in various legal and regulatory proceedings at both the federal and state levels. The Company is also subject to claims and lawsuits that arise primarily in the ordinary course of business. It is the opinion of management that the disposition or ultimate resolution of such proceedings, claims and lawsuits will not have a material adverse effect on the financial position, results of operations and cash flows of the Company.

Commitments

In December 2014, the Company committed to buy $6,900 in IT equipment which was received in January 2015 and financed with a capital leasing arrangement. Payments are due quarterly commencing on March 1, 2015.

Note 11: Disclosures About Fair Value of Financial Instruments

ASC Topic 820, *Fair Value Measurements*, defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Topic 820 also specifies a fair value hierarchy, which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value:

Level 1 Quoted prices in active markets for identical assets or liabilities

Level 2 Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities

Level 3 Unobservable inputs that are supported by little or no market activity and are significant to the fair value of the assets or liabilities

Southwest Power Pool, Inc.

Notes to Financial Statements

(*in Thousands*)

December 31, 2014 and 2013

		Fair Value Measurements Using		
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2014				
Cash Equivalents	$ 11,241	$ 11,241	$ -	$ -
Mutual Funds				
Equity	3,186	1,075	2,111	-
Fixed Income	2,732	332	2,400	-
Financials	610	-	610	-
Alternative Assets	271	271	-	-
Domestic Common Stock				
Consumer discretionary	417	417	-	-
Consumer staples	393	393	-	-
Energy	229	229	-	-
Financial	452	452	-	-
Healthcare	456	456	-	-
Industrials	404	404	-	-
Information technology	574	574	-	-
Materials	172	172	-	-
Telecommunication	37	37	-	-
Utilities	125	125	-	-
Foreign Stocks				
Industrials	41	41	-	-
Interest Rate Swap Agreements	(2,462)	-	(2,462)	-

Southwest Power Pool, Inc.

Notes to Financial Statements

(*in Thousands*)

December 31, 2014 and 2013

		Fair Value Measurements Using		
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2013				
Cash Equivalents	$ 14,238	$ 14,238	$ -	$ -
Mutual Funds				
Equity	3,149	1,023	2,126	-
Fixed Income	2,282	345	1,937	-
Financials	498	-	498	-
Alternative Assets	333	333	-	-
Domestic Common Stock				
Consumer discretionary	365	365	-	-
Consumer staples	351	351	-	-
Energy	260	260	-	-
Financial	405	405	-	-
Healthcare	384	384	-	-
Industrials	385	385	-	-
Information technology	512	512	-	-
Materials	163	163	-	-
Telecommunication	39	39	-	-
Utilities	94	94	-	-
Foreign Stocks				
Industrials	38	38	-	-
Interest Rate Swap Agreements	(934)	-	(934)	-

Following is a description of the valuation methodologies used for assets and liabilities measured at fair value on a recurring basis and recognized in the accompanying balance sheets, as well as the general classification of such assets and liabilities pursuant to the valuation hierarchy. There have been no significant changes in the valuation techniques during the year ended December 31, 2014.

Investments

Where quoted market prices are available in an active market, securities are classified within Level 1 of the valuation hierarchy. If quoted market prices are not available, then fair values are estimated by using quoted prices of securities with similar characteristics or independent asset pricing services and pricing models, the inputs of which are market-based or independently sourced market parameters, including, but not limited to, yield curves, interest rates, volatilities, prepayments, defaults, cumulative loss projections and cash flows. Such securities are classified in Level 2 of the valuation hierarchy. In certain cases where Level 1 or Level 2 inputs are not available, securities are classified within Level 3 of the hierarchy. At December 31, 2014 and 2013, the company does not hold any assets valued using Level 3 inputs.

Interest Rate Swap Agreements

The fair value is estimated using forward-looking interest rate curves and discounted cash flows that are observable or that can be corroborated by observable market data and, therefore, are classified within Level 2 of the valuation hierarchy.

Cash Equivalents

The fair value of money market mutual funds included in cash equivalents are estimated using quoted prices in active markets for identical assets or liabilities and, therefore, are classified within level 1 of the valuation hierarchy.

The Company has no assets or liabilities measured and recognized in the accompanying balance sheets on a nonrecurring basis.

The following methods were used to estimate the fair value of all other financial instruments recognized in the accompanying balance sheets at amounts other than fair value.

Restricted Cash Deposits

For these short-term instruments, the carrying amount is a reasonable estimate of fair value.

Customer Deposits

The carrying amount is a reasonable estimate of fair value.

Long-term Debt

Fair value is estimated based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities.

The following table presents estimated fair values of the Company's financial instruments at December 31, 2014 and 2013.

	2014		2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets				
Cash and cash equivalents	$ 57,534	$ 57,534	$ 35,262	$ 35,262
Restricted cash deposits	$ 222,285	$ 222,285	$ 76,713	$ 76,713
Investments	$ 10,099	$ 10,099	$ 9,258	$ 9,258
Financial liabilities				
Customer deposits	$ 222,285	$ 222,285	$ 76,713	$ 76,713
Long-term debt	$ 272,260	$ 274,271	$ 258,258	$ 264,200
Swap agreements	$ 2,462	$ 2,462	$ 934	$ 934

Note 12: Subsequent Events

Subsequent events have been evaluated through the date of the Independent Auditor's Report, which is the date the financial statements were available to be issued.

ATTACHMENT 8

2014 ACTUAL COST-TO-BUDGET COMPARISON

AND

2014 AUDITED FINANCIAL REPORT

FOR

TEXAS RELIABILITY ENTITY, INC.

May 4, 2015

Michael Walker, CFO
Susan Turpen, Controller
North American Electric Reliability Corporation
3343 Peachtree Road, NE Floor East Tower – Suite 400
Atlanta, GA 30326

Subject: Texas Reliability Entity (Texas RE) 2014 Actual Cost-to-Budget Comparison

Dear Mr. Walker and Ms. Turpen,

Texas Reliability Entity (Texas RE) has completed the 2014 True-Up Analysis. The budget comparisons are compared to the 2014 Texas RE budget, formally approved by FERC.

Texas RE did not use Statutory funds for Non-statutory purposes.

Texas RE's policy is to allocate indirect expenses to programs based on the pro-rata share of FTEs to total program FTEs.

Texas RE maintains a $2,000,000 cash reserve balance according to the policy approved by the Texas RE Board of Directors.

The significant expense variances at the aggregate statutory level are explained below. The explanations for the expense variances by statutory program area are provided in the attached files below.

INCOME

Total Statutory Income is over budget by $23k or 0.2%. $17,000 in Penalty revenue was collected the end of June 2013 that was not included in the 2014 budget number. According to the NERC requirements, this money should have been applied to the 2014 budget. Texas RE recognizes revenue related to fines and penalties in the period in which it is earned. Interest Revenue was $12,620 less than budget due to lower than anticipated interest rates.

EXPENSES

Personnel Expenses are $829,619 or 9.7% below budget due to FTE vacancies, the result of employee turnover and hiring of replacement employees.

Travel and Meeting Expenses are $153,490 or 30.9% less than budget mainly due to cost savings efforts in all areas.

Other Operating Expenses are $1,015,143 or 34% less than budget. Consultants and Contracts are under budget due to work being performed by staff in place of consultants or contractors. Operating expenses for the building are included in Rent and improvements. The amount is adjusted annually based on actual usage for the previous 12 months. Texas RE's portion of the actual expense was less than

budgeted. Professional fees are less than budget mainly due to the Enforcement department not utilizing the legal fees budgeted for a potential contested case. Depreciation is less than budget due to a adjusting entry made to correct Fixed Assets.

FIXED ASSETS

Budgeted assets were not acquired in 2014 causing actual expenditures to be 26.5% less than budgeted.

Texas RE has reported large budget underruns in the past years. As you can tell from the 2015 and 2016 budgets, the budgeting process has been refined to more accurately align costs with budget amount in the future.

Although Texas RE ended the year $1.9 million under budget, Texas RE completed its intended activities for 2014.

Texas RE completed 30 Non-CIP audits, 8 CIP audits with Critical Cyber Assets (CCA's), 19 CIP audits without CCA's, and 1 spot check.

Texas RE identified 80 non-compliance matters and completely resolved 144 violations to reduce violation caseload from 105 to 41.

In 2014, a total of 91 events were examined, as follows: 77 – non-qualified events (below threshold for Categories 1-5), 11 -Category 1, 2 - Category 2 and 1 - Category 3. There were no Category 4 or 5 level events.

100 technical feasibility exceptions were processed in 2014.

Texas RE verified mitigation plans or mitigation activities for 90 possible violations.

In 2014, Texas RE processed 22 entity registrations, 16 entity deactivations/de-registrations and 5 entity name changes. Also, Texas RE conducted 1 TOP certification and 1 certification review associated with a control center relocation.

If you have any questions on the report or the attached spreadsheet, please call me at the number below.

Thank you.

Judy Foppiano

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Texas Reliability Entity, Inc.
2014 Statutory & Non-Statutory Statement of Activities
Audited

Total Statutory & State (Non-Statutory) Combined

Funding	2014 Actual	2014 Budget	2014 Variance from Budget	%
ERO Funding				
Assessments	$ 10,509,309	$ 10,509,309	$ -	
Penalty Sanctions	419,833	402,834	17,000	
Total ERO Funding	**$ 10,929,142**	**$ 10,912,143**	**$ 17,000**	**0.2%**
Membership Fees	$ 19,500	$ 18,250	$ 1,250	
PUCT Fees	970,000	970,000	-	
Interest	2,179	14,466	(12,287)	
Total Funding	**$ 11,920,821**	**$ 11,914,859**	**$ 22,963**	**0.2%**
Expenses				
Personnel Expenses				
Salaries	$ 6,455,026	$ 6,648,384	$ (193,358)	
Payroll Taxes	442,710	619,272	(176,562)	
Employee Benefits	816,577	1,053,804	(237,227)	
Savings & Retirement	671,260	959,729	(288,469)	
Total Personnel Expenses	**$ 8,385,572**	**$ 9,281,188**	**$ (895,616)**	**-9.6%**
Meeting & Travel Expenses				
Meetings	$ 38,914	$ 95,213	$ (56,299)	
Travel	295,299	410,072	(114,774)	
Conference Expenses	8,703	3,500	5,203	
Total Meeting & Travel Expenses	**$ 342,915**	**$ 508,785**	**$ (165,870)**	**-32.6%**
Operating Expenses				
Consultants & Contracts	$ 319,830	$ 514,926	$ (195,096)	
Rent & Improvements	538,638	555,287	(16,649)	
Office Costs	588,464	693,244	(104,779)	
Professional Services	414,739	1,107,846	(693,107)	
Depreciation	214,110	301,186	(87,076)	
Total Operating Expenses	**$ 2,075,782**	**$ 3,172,489**	**$ (1,096,707)**	**-34.6%**
Indirect Allocation				
Total Expenses	**$ 10,804,270**	**$ 12,962,462**	**$ (2,158,192)**	**-16.6%**
Change in Assets	$ 1,116,552	$ (1,047,603)	$ 2,164,154	-206.6%
Fixed Assets				
Depreciation	$ (214,110)	$ (263,213)	$ 49,103	
Computer & Software CapEx	-	42,000	(42,000)	
Allocation of Fixed Assets				
Incr(Dec) in Fixed Assets	**$ (214,110)**	**$ (221,213)**	**$ 7,103**	**-3.2%**
TOTAL BUDGET	**$ 10,590,159**	**$ 12,741,249**	**$ (2,151,089)**	**-16.9%**
Change in Working Captial	**$ 1,330,662**	**$ (826,390)**	**$ 2,157,052**	
FTE's	57.0	65.0	(8.0)	

Texas Reliability Entity, Inc.
2014 Statutory Statement of Activities
Audited

Statutory

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$10,509,309	$10,509,309	$ -	
Penalty Sanctions	419,833	402,833	17,000	
Total ERO Funding	**$10,929,142**	**$10,912,142**	**$ 17,000**	**0.2%**
Membership Fees	19,500	18,249	1,251	
Interest	1,846	14,466	(12,620)	
Total Funding	**$10,950,488**	**$10,944,857**	**$ 22,631**	**0.2%**
Expenses				
Personnel Expenses				
Salaries	$ 5,886,607	$ 6,087,780	$ (201,173)	
Payroll Taxes	402,764	571,041	(168,277)	
Employee Benefits	791,460	971,875	(180,415)	
Savings & Retirement	602,973	882,728	(279,755)	
Total Personnel Expenses	**$ 7,683,804**	**$ 8,513,423**	**$ (829,619)**	**-9.7%**
Meeting & Travel Expenses				
Meetings	$ 38,914	$ 95,213	$ (56,299)	
Travel	295,198	397,592	(102,394)	
Conference Expenses	8,703	3,500	5,203	
Total Meeting & Travel Expenses	**$ 342,815**	**$ 496,305**	**$ (153,490)**	**-30.9%**
Operating Expenses				
Consultants & Contracts	$ 317,722	$ 496,071	$ (178,349)	
Rent & Improvements	489,912	556,864	(66,952)	
Office Costs	575,939	639,497	(63,558)	
Professional Services	421,521	1,027,088	(605,567)	
Depreciation	162,496	263,213	(100,717)	
Total Operating Expenses	**$ 1,967,590**	**$ 2,982,733**	**$ (1,015,143)**	**-34.0%**
Indirect Allocation				
Total Expenses	**$ 9,994,209**	**$11,992,461**	**$ (1,998,252)**	**-16.7%**
Change in Assets	$ 956,279	$ (1,047,604)	$ 2,003,883	-191.3%
Fixed Assets				
Depreciation	$ (162,496)	$ (263,213)	$ 100,717	
Computer & Software CapEx	-	42,000	(42,000)	
Allocation of Fixed Assets	-	-	-	
Incr(Dec) in Fixed Assets	**$ (162,496)**	**$ (221,213)**	**$ 58,717**	**-26.5%**
TOTAL BUDGET	**$ 9,831,713**	**$11,771,248**	**$ (1,939,534)**	**-16.5%**
Change in Working Captial	**$ 1,118,775**	**$ (826,390)**	**$ 1,945,164**	
FTE's	**52.00**	**60.00**	**(8.00)**	

Texas Reliability Entity, Inc.
2014 Statement of Activities
Audited

RELIABILITY STANDARDS

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$ 433,387	$ 433,387	$ -	0.0%
Penalty Sanctions	12,958	16,359	(3,401)	
Total ERO Funding	$ 446,345	$ 449,746	$ -	0.0%
Membership Fees	792	741	51	
Interest	75	-	75	
Total Funding	$ 447,212	$ 450,487	$ 126	0.0%
Expenses				
Personnel Expenses				
Salaries	$ 236,969	$ 184,058	$ 52,911	
Payroll Taxes	16,668	20,720	(4,052)	
Employee Benefits	28,259	28,527	(268)	
Savings & Retirement	24,593	26,688	(2,095)	
Total Personnel Expenses	**$ 306,489**	**$ 259,993**	**$ 46,496**	**17.9%**
Meeting & Travel Expenses				
Meetings	$ 264	$ -	$ 264	
Travel	13,142	11,268	1,874	
Total Meeting & Travel Expenses	**$ 13,406**	**$ 11,268**	**$ 2,138**	**19.0%**
Operating Expenses				
Consultants & Contracts	$ 350	$ 10,992	$ (10,642)	
Office Costs	232	1,004	(773)	
Total Operating Expenses	**$ 582**	**$ 11,996**	**$ (11,415)**	**-95.2%**
Indirect Allocation	$ 117,554	$ 176,009	$ (10,642)	**-6.0%**
Total Expenses	**$ 438,030**	**$ 459,267**	**$ (21,237)**	**-4.6%**
Change in Assets	$ 9,182	$ (8,780)	$ 17,961	-204.6%
Fixed Assets				
Computer & Software CapEx	-	-	-	
Furniture & Fixture CapEx	-	-	-	
Allocation of Fixed Assets	(5,015)	(8,780)	-	
Incr(Dec) in Fixed Assets	**$ (5,015)**	**$ (8,780)**	**$ 3,765**	**-42.9%**
TOTAL BUDGET	**$ 433,015**	**$ 450,487**	**$ (17,472)**	**-3.9%**
Change in Working Captial	**$ 14,197**	**$ -**	**$ 14,197**	
FTE's	1.25	2.00	-0.75	

Reliability Standards

Variances > +/- $10,000 and 10%

Total Personnel Expenses are over budget 17.9% due to FTE reallocation among departments. The realignment of FTEs included a high salaried employee being assigned from another department resulting in the budget overrun.

Meeting and Travel expense is 19% greater than budget due to staff attending meetings not anticipated in the budget.

Operating expenses are 95.2% less than budget due to work being performed by staff in place of Consultants and Contractors.

Indirect Allocation and Allocation of Fixed Assets is less than budget due to FTE realignment among departments.

Total Expenditures are 3.9% less than budget.

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CMEP

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$ 8,994,237	$8,994,237	$ -	
Penalty Sanctions	334,311	327,174	7,137	
Total ERO Funding	**$ 9,328,548**	**$9,321,411**	**$ 7,137**	**0.1%**
Membership Fees	15,837	14,822	1,015	
Interest	1,500	-	-	
Total Funding	**$ 9,345,885**	**$9,336,233**	**$ 15,290**	**0.2%**
Expenses				
Personnel Expenses				
Salaries	$ 3,211,066	$3,520,283	$ (309,217)	
Payroll Taxes	233,992	357,639	(123,647)	
Employee Benefits	415,428	640,999	(225,571)	
Savings & Retirement	324,949	510,441	(185,492)	
Total Personnel Expenses	**$ 4,185,436**	**$5,029,362**	**$ (843,926)**	**-16.8%**
Meeting & Travel Expenses				
Meetings	$ 1,853	$ -	$ 1,853	
Travel	124,914	236,385	(111,471)	
Conference Expenses	-	-	-	
Total Meeting & Travel Expenses	**$ 126,767**	**$ 236,385**	**$ (109,618)**	**-46.4%**
Operating Expenses				
Consultants & Contracts	$ 146,808	$ 287,280	$ (140,472)	
Rent & Improvements	-	-	-	
Office Costs	13,894	13,626	268	
Professional Services	240	425,000	(424,760)	
Depreciation	-	-	-	
Total Operating Expenses	**$ 160,942**	**$ 725,906**	**$ (564,964)**	**-77.8%**
Indirect Allocation	$ 3,032,882	$3,520,184	$ (487,302)	-13.8%
Total Expenses	**$ 7,506,027**	**$9,511,837**	**$ (2,005,810)**	**-21.1%**
Change in Assets	**$ 1,839,858**	**$ (175,605)**	**$ 2,021,099**	**-1150.9%**
Fixed Assets				
Depreciation	$ -	$ -	$ -	
Computer & Software CapEx	-	-	-	
Allocation of Fixed Assets	(129,395)	(175,604)	46,209	
Incr(Dec) in Fixed Assets	**$ (129,395)**	**$ (175,604)**	**$ 46,209**	**-26.3%**
TOTAL BUDGET	**$ 7,376,633**	**$9,336,233**	**$ (1,959,600)**	**-21.0%**
Change in Working Captial	**$ 1,969,253**	**$ -**	**$ 1,974,890**	
FTE's	32.25	40.00	(7.75)	

CMEP

Variances > +/- $10,000 and 10%

This department ended the year 21% less than budget due to vacancies throughout the year and FTE alignment among departments.

All areas were affected with having less personnel costs and less travel.

Consultants and Contracts are under budget due to work expected to be performed by consultants being performed by FTEs.

Professional services are less than budget due the Enforcement department not utilizing the legal fees budgeted for a potential contested case.

The FTE realignment among departments also caused a favorable variance in the Indirect Allocation and the Allocation of Fixed Assets.

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Reliability Assessments & Performance Analysis

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$ 1,545,048	$ 1,407,540	$ 137,508	
Penalty Sanctions	51,831	38,852	12,979	
Total ERO Funding	**$ 1,596,879**	**$ 1,446,392**	**$ 150,487**	**10.4%**
Membership Fees	2,178	1,760	418	
Interest	206	-	206	
Total Funding	**$ 1,599,263**	**$ 1,448,152**	**$ 151,111**	**10.4%**
Expenses				
Personnel Expenses				
Salaries	$ 812,342	$ 689,636	$ 122,706	
Payroll Taxes	57,453	52,409	5,044	
Employee Benefits	108,139	95,813	12,326	
Savings & Retirement	87,716	99,997	(12,281)	
Total Personnel Expenses	**$ 1,065,650**	**$ 937,855**	**$ 127,795**	**13.6%**
Meeting & Travel Expenses				
Meetings	$ 658	$ -	$ 658	
Travel	59,392	52,288	7,104	
Total Meeting & Travel Expenses	**$ 60,050**	**$ 52,288**	**$ 7,762**	**14.8%**
Operating Expenses				
Consultants & Contracts	$ 1,050	$ -	$ 1,050	
Office Costs	30,790	60,840	(30,050)	
Depreciation	-	5,000	(5,000)	
Total Operating Expenses	**$ 31,840**	**$ 65,840**	**$ (34,000)**	**-51.6%**
Indirect Allocation	$ 470,214	$ 418,022	$ 52,192	12.5%
Total Expenses	**$ 1,627,754**	**$ 1,474,005**	**$ 153,749**	**10.4%**
Change in Assets	**$ (28,491)**	**$ (25,853)**	**$ (2,638)**	**10.2%**
Fixed Assets				
Depreciation	$ -	$ (5,000)	$ 5,000	
Computer & Software CapEx	-	-	-	
Allocation of Fixed Assets	(20,061)	(20,853)	792	
Incr(Dec) in Fixed Assets	**$ (20,061)**	**$ (25,853)**	**$ 5,792**	**-22.4%**
TOTAL BUDGET	**$ 1,607,693**	**$ 1,448,152**	**$ 159,541**	**11.0%**
Change in Working Captial	**$ (8,429)**	**$ 0**	**$ (8,429)**	
FTE's	5.00	4.75	0.25	

RAPA

Variances > +/- $10,000 and 10%

The Situation Analysis department was rolled in the Reliability Standards Department during 2014 causing this department to be over budget in all areas, with a total budget variance of 11%.

Savings and Retirement is under budget 12.3% due to employees not participating fully in the retirement plan.

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Situation Awareness and Infrastructure Security Program

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$ -	$ 137,508	$ (137,508)	
Penalty Sanctions	-	6,135	(6,135)	
Total ERO Funding	**$ -**	**$ 143,643**	**$ (143,643)**	**-100.0%**
Membership Fees	-	278	(278)	
Interest	-	-	-	
Total Funding	**$ -**	**$ 143,921**	**$ (143,921)**	**-100.0%**
Expenses				
Personnel Expenses				
Salaries	$ -	$ 48,270	$ (48,270)	
Payroll Taxes	-	10,318	(10,318)	
Employee Benefits	-	14,310	(14,310)	
Savings & Retirement	-	6,999	(6,999)	
Total Personnel Expenses	**$ -**	**$ 79,897**	**$ (79,897)**	**-100.0%**
Meeting & Travel Expenses				
Meetings	$ -	$ 1,314	$ (1,314)	
Travel	-	-	-	
Conference Expenses	-	-	-	
Total Meeting & Travel Expenses	**$ -**	**$ 1,314**	**$ (1,314)**	**-100.0%**
Operating Expenses				
Consultants & Contracts	$ -	$ -	$ -	
Rent & Improvements	-	-	-	
Office Costs	-	-	-	
Professional Services	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ -**	**$ -**	**$ -**	**0.0%**
Indirect Allocation	$ -	$ 66,003	$ (66,003)	-100.0%
Total Expenses	**$ -**	**$ 147,214**	**$ -**	**-100.0%**
Change in Assets	**$ -**	**$ (3,293)**	**$ -**	**100.0%**
Fixed Assets				
Depreciation	$ -	$ -	$ -	
Allocation of Fixed Assets	-	(3,293)	3,293	
Incr(Dec) in Fixed Assets	**$ -**	**$ (3,293)**	**$ 3,293**	**-100.0%**
TOTAL BUDGET	**$ -**	**$ 143,920**	**$ -**	**-100.0%**
Change in Working Captial	**$ -**	**$ -**	**$ 0**	
FTE's	-	0.75	(0.75)	

This department was included in the RAPA department for actual costs in 2014.

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TRAINING AND EDUCATION

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$ 377,493	$ 377,493	$ -	
Penalty Sanctions	20,732	14,314	6,418	
Total ERO Funding	$ 398,225	$ 391,807	$ 6,418	**1.6%**
Membership Fees	693	648	45	
Interest	66	-	66	
Total Funding	**$ 398,984**	**$ 392,456**	**$ 6,528**	**1.7%**
Expenses				
Personnel Expenses				
Salaries	$ 152,475	$ 121,945	$ 30,530	
Payroll Taxes	10,136	14,985	(4,849)	
Employee Benefits	25,866	28,111	(2,245)	
Savings & Retirement	15,395	17,682	(2,287)	
Total Personnel Expenses	**$ 203,872**	**$ 182,722**	**$ 21,150**	**11.6%**
Meeting & Travel Expenses				
Meetings	$ 16,339	$ 62,136	$ (45,797)	
Travel	5,554	312	5,242	
Conference Expenses	6,380	-	6,380	
Total Meeting & Travel Expenses	**$ 28,273**	**$ 62,448**	**$ (34,175)**	**-54.7%**
Operating Expenses				
Office Costs	2,165	960	1,205	
Total Operating Expenses	**2,165**	**960**	**1,205**	**125.5%**
Indirect Allocation	$ 188,086	$ 154,008	$ 34,078	22.1%
Total Expenses	**$ 422,396**	**$ 400,138**	**$ 22,258**	**5.6%**
Change in Assets	$ (23,412)	$ (7,683)	$ (15,728)	204.7%
Fixed Assets				
Computer & Software CapEx	-	-	-	
Allocaton of Fixed Assets	(8,024)	(7,683)	(341)	
Incr(Dec) in Fixed Assets	**$ (8,024)**	**$ (7,683)**	**$ (341)**	**4.4%**
TOTAL BUDGET	**$ 414,372**	**$ 392,456**	**$ 21,916**	**5.6%**
Change in Working Captial	**$ (15,387)**	**$ -**	**$ (15,387)**	
FTE's	2.00	1.75	0.25	

Training and Education

Variances > +/- $10,000 and 10%

The Training and Education department is 5.6% over budget overall.

FTE reassignment causes Personnel expenses to be 11.6% over budget. The FTE reassignment also causes the Indirect Allocation and the Fixed Asset allocation to be under budget.

Meeting and Travel expenses are under budget 54.7% because a registered entity hosted the fall workshop that was budgeted at full Texas RE expense.

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General and Administrative

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$ (840,856)	$ (840,856)	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	$ (840,856)	$ (840,856)	$ -	
Membership Fees	-	-	-	
Interest	-	14,466	(14,466)	
Total Funding	$ (840,856)	$ (826,390)	$ (14,466)	1.8%
Expenses				
Personnel Expenses				
Salaries	$ 481,035	$ 539,315	$ (58,280)	
Payroll Taxes	11,614	33,225	(21,611)	
Employee Benefits	4,364	7,906	(3,542)	
Savings & Retirement	44,398	78,201	(33,803)	
Total Personnel Expenses	**$ 541,411**	**$ 658,647**	**$ (117,236)**	**-17.8%**
Meeting & Travel Expenses				
Meetings	$ 12,855	$ 21,427	$ (8,572)	
Travel	68,878	57,045	11,833	
Conference Expenses	-	-	-	
Total Meeting & Travel Expenses	**$ 81,733**	**$ 78,472**	**$ 3,261**	**4.2%**
Operating Expenses				
Consultants & Contracts	$ 53,033	$ 42,600	$ 10,433	
Rent & Improvements	483,548	510,864	(27,316)	
Office Costs	70,262	27,427	42,835	
Professional Services	249,850	384,000	(134,150)	
Depreciation	162,496	258,213	(95,717)	
Total Operating Expenses	**1,019,188**	**1,223,104**	**(203,916)**	**-16.7%**
Indirect Allocation	$ (1,642,332)	$ (1,960,223)	$ (134,150)	6.8%
Total Expenses	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Assets	$ (840,856)	$ (826,390)	$ (14,466)	1.8%
Fixed Assets				
Depreciation	$ (162,496)	$ (258,213)	$ 95,717	-37.1%
Computer & Software CapEx	-	-	-	
Allocation of Fixed Assets	162,496	258,213	(95,717)	
Incr(Dec) in Fixed Assets	**$ 0**	**$ -**	**$ 0**	**0.0%**
TOTAL BUDGET	**$ 0**	**$ -**	**$ 0**	**0%**
Change in Working Captial	**$ (840,856)**	**$ (826,390)**	**$ (14,466)**	
FTE's	1.00	1.75	(0.75)	

General and Administrative

Variances > +/- $10,000 and 10%

Personnel expenses are under budget $117,236 or 17.8%. FTE reassignment causes the favorable variance in this category.

Total Operating Expenses are under budget $203,916 or 16.7%. Consultants and Contracts are over budget 24.5% due to engaging an executive consultant to help with strategic planning that was not budgeted. Rent and Improvements are under budget due to operating expenses for the building being included in this category. The amount is adjusted annually based on actual usage for the previous twelve months. Texas RE's portion of the actual expense was less than budget. Professional Services included budget for fees for a Board of Directors search which was not used. Depreciation is less than budget due to a adjusting entry made to correct Fixed Assets.

Again, due to FTE reassignment the Indirect Allocation and the Allocation of Fixed Assets is less than budget.

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LEGAL AND REGULATORY

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	%
ERO Funding				
Total Funding	$ -	$ -	$ -	0%
Expenses				
Personnel Expenses				
Salaries	$ 295,823	$ 193,467	$ 102,356	
Payroll Taxes	22,302	28,876	(6,574)	
Employee Benefits	40,116	50,710	(10,595)	
Savings & Retirement	27,571	28,053	(482)	
Total Personnel Expenses	**$ 385,812**	**$ 301,106**	**$ 84,705**	**28.1%**
Meeting & Travel Expenses				
Travel	$ 8,996	$ 17,099	$ (8,103)	
Conference Expenses	-	-	-	
Total Meeting & Travel Expenses	**$ 8,996**	**$ 17,099**	**$ (8,103)**	**-47.4%**
Operating Expenses				
Consultants & Contracts	$ 4,700	$ 2,299	$ 2,401	
Office Costs	2,686	5,392	(2,706)	
Professional Services	17,326	30,000	(12,674)	
Depreciation	-	-	-	
Total Operating Expenses	**$ 24,712**	**$ 37,691**	**$ (12,979)**	**-34.4%**
Indirect Allocation	$ (419,520)	$ (419,520)	$ (12,674)	**3.0%**
Total Expenses	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Assets	$ -	$ -	$ -	0.0%
Fixed Assets				
Computer & Software CapEx	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	**0.0%**
TOTAL BUDGET	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Working Captial	**$ -**	**$ -**	**$ -**	
FTE's	2.00	3.00	(1.00)	

Legal and Regulatory

Variances > +/- $10,000 and 10%

Personnel expenses are greater than budget due to FTE reassignment. The reassignment resulted in one less FTE, but with higher salaried FTEs being assigned to this department.

Less travel for NERC, regional entity and Trade meetings was required with reduced FTE count.

Professional services budget included legal fees for a potential contested case which was not needed.

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INFORMATION TECHNOLOGY

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total Funding	$ -	$ -	$ -	0.0%
Expenses				
Personnel Expenses				
Salaries	$ 325,621	$ 336,221	$ (10,600)	
Payroll Taxes	23,823	20,306	3,517	
Employee Benefits	103,086	37,002	66,084	
Savings & Retirement	37,647	48,752	(11,105)	
Total Personnel Expenses	**$ 490,176**	**$ 442,281**	**$ 47,895**	**10.8%**
Meeting & Travel Expenses				
Meetings	$ 224	$ 2,900	$ (2,676)	
Travel	7,923	17,556	(9,633)	
Conference Expenses	2,322	3,500	(1,178)	
Total Meeting & Travel Expenses	**$ 10,469**	**$ 23,956**	**$ (13,487)**	**-56.3%**
Operating Expenses				
Consultants & Contracts	$ 32,879	$ 37,500	$ (4,621)	
Rent & Improvements	6,364	-	6,364	
Office Costs	426,837	486,538	(59,701)	
Professional Services	71,712	81,000	(9,288)	
Total Operating Expenses	**537,793**	**605,038**	**(67,245)**	**-11.1%**
Indirect Allocation	$ (1,038,438)	$ (1,071,275)	$ (4,621)	0.4%
Total Expenses	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Assets	$ -	$ -	$ -	0.0%
Fixed Assets				
Computer & Software CapEx	-	42,000	(42,000)	
Furniture & Fixture CapEx	-	-	-	
Allocation of Fixed Assets		(42,000)	42,000	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	**0.0%**
TOTAL BUDGET	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Working Captial	**$ -**	**$ -**	**$ -**	
FTE's	4.50	2.50	2.00	

Information Technology

Variances > +/- $10,000 and 10%

Personnel expenses are 10.8% greater than budget due to FTE reassignment. Training and education not included in the budget caused the Employee Benefits overrun..

Travel and meeting expense is under budget 56.3% due to cost savings efforts and emphasis on attending meetings by conference call and Web Ex.

Operating Expenses are 11.1% less than budget primarily due to leased equipment budgeted in Office Costs beginning in March 2014 but did not occur until June 2014.

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HUMAN RESOURCES

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total Funding	$ -	$ -	$ -	0.0%
Expenses				
Personnel Expenses				
Salaries	$ 85,479	$ 91,052	$ (5,573)	
Payroll Taxes	6,171	12,804	(6,633)	
Employee Benefits	24,577	36,740	(12,163)	
Savings & Retirement	9,484	13,203	(3,719)	
Total Personnel Expenses	**$ 125,711**	**$ 153,799**	**$ (28,088)**	**-18.3%**
Meeting & Travel Expenses				
Meetings	$ 6,721	$ 8,750	$ (2,029)	
Travel	4,084	1,705	2,379	
Total Meeting & Travel Expenses	**$ 10,805**	**$ 10,455**	**$ 350**	**3.3%**
Operating Expenses				
Consultants & Contracts	$ 78,727	$ 80,400	$ (1,673)	
Office Costs	6,103	3,652	2,451	
Professional Services	-	-	-	
Total Operating Expenses	**$ 84,830**	**$ 84,052**	**$ 778**	**0.9%**
Indirect Allocation	$ (221,346)	$ (248,306)	$ 26,960	-10.9%
Total Expenses	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Assets	$ -	$ -	$ -	0.0%
Fixed Assets				
Computer & Software CapEx	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	**0.0%**
TOTAL BUDGET	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Working Captial	**$ -**	**$ -**	**$ -**	
FTE's	1.00	1.00	-	

Human Resources

Variances > +/- $10,000 and 10%

Personnel expenses are 18.3% less than budget primarily due to Employee Benefits. Employee benefits includes tuition reimbursement which was not fully utilized in 2014.

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FINANCE AND ACCOUNTING

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
ERO Funding				
Total Funding	$ -	$ -	$ -	0.0%
Expenses				
Personnel Expenses				
Salaries	$ 285,797	$ 278,344	$ 7,453	
Payroll Taxes	20,601	18,970	1,631	
Employee Benefits	43,215	30,277	12,938	
Savings & Retirement	29,631	40,360	(10,729)	
Total Personnel Expenses	**$ 379,244**	**$ 367,951**	**$ 11,293**	**3.1%**
Meeting & Travel Expenses				
Travel	$ 2,316	$ 2,620	$ (304)	
Conference Expenses	-	-	-	
Total Meeting & Travel Expenses	**$ 2,316**	**$ 2,620**	**$ (304)**	**-11.6%**
Operating Expenses				
Consultants & Contracts	$ 175	$ 35,000	$ (34,825)	
Office Costs	22,971	40,058	(17,086)	
Professional Services	82,393	153,088	(70,695)	
Depreciation	-	-	-	
Total Operating Expenses	**$ 105,539**	**$ 228,146**	**$ (122,606)**	**-53.7%**
Indirect Allocation	$ (487,100)	$ (598,717)	$ 111,617	-18.6%
Total Expenses	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Assets	$ -	$ -	$ -	0.0%
Fixed Assets				
Computer & Software CapEx	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	**0.0%**
TOTAL BUDGET	**$ -**	**$ -**	**$ -**	**0.0%**
Change in Working Captial	**$ -**	**$ -**	**$ -**	
FTE's	3.00	3.00	-	

Finance and Accounting

Variances > +/- $10,000 and 10%

Total Operating Expenses are under budget $122,606 or 53.7%. Employees were utilized where a consultant was budgeted. An increase for commercial insurance and accounting fees was not as great an anticipated in the budget.

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STATE (NON-STATUTORY)

Funding	2014 Actual	2014 Budget	2014 Variance from Budget Over (Under)	
PUCT	970,000	970,000	-	
Interest	333	-	333	
Total Funding	**$ 970,333**	**$ 970,000**	**$ 333**	**0.0%**
Expenses				
Personnel Expenses				
Salaries	$ 568,420	$ 560,604	$ 7,816	
Payroll Taxes	39,946	48,231	(8,285)	
Employee Benefits	25,117	81,929	(56,812)	
Savings & Retirement	68,287	77,001	(8,714)	
Total Personnel Expenses	**$ 701,770**	**$ 767,765**	**$ (65,995)**	**-8.6%**
Meeting & Travel Expenses				
Travel	100	12,480	(12,380)	
Total Meeting & Travel Expenses	**$ 100**	**$ 12,480**	**$ (12,380)**	**-99.2%**
Operating Expenses				
Consultants & Contracts	$ -	$ 18,855	$ (18,855)	
Rent & Improvements	38,560	48,423	(9,863)	
Office Costs	8,862	53,747	(44,885)	
Professional Services	9,157	30,758	(21,601)	
Depreciation	51,615	37,973	13,642	
Total Operating Expenses	**$ 108,194**	**$ 189,756**	**$ (81,562)**	**-43.0%**
Indirect Allocation				
Total Expenses	**$ 810,062**	**$ 970,000**	**$ (159,937)**	**-16.5%**
Change in Assets	$ 160,271	$ -	$ (159,604)	0.0%
Fixed Assets				
Depreciation				
Computer & Software CapEx				
Furniture & Fixture CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvement CapEx	-	-	-	
Allocation of Fixed Assets	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	**0.0%**
TOTAL BUDGET	**$ 810,062**	**$ 970,000**	**$ (159,939)**	**-16.5%**
Change in Working Captial	**$ 160,271**	**$ -**	**$ 335**	
FTE's	**5.00**	**5.00**	**-**	

Texas Reliability Entity, Inc.
Penalty Sanctions

Date Invoiced	Date Rec'd		Amount	Year to Recognize for BP&B					
				2011	2012	2013	2014	2015	2016
			$ 20,000	$ 20,000					
			$ 198,600		$ 198,600				
			$ 150,000		$ 150,000				
			$ 28,000		$ 28,000				
			$ 18,000		$ 18,000				
			$ 3,000		$ 3,000				
			$ 35,000		$ 35,000				
			$ 900		$ 900				
			$ 900		$ 900				
			$ 900		$ 900				
			$ 900		$ 900				
			$ 900		$ 900				
			$ 2,500		$ 2,500				
			$ 50,000		$ 50,000				
			$ 3,000		$ 3,000				
			$ 12,000		$ 12,000				
			$ 4,000		$ 4,000				
			$ 16,000		$ 16,000				
			$ 9,000		$ 9,000				
			$ 11,000		$ 11,000				
			$ 6,000		$ 6,000				
			$ 1,230		$ 1,230				
			$ 8,000		$ 8,000				
			$ 5,000		$ 5,000				
			$ 3,000		$ 3,000				
			$ 5,000		$ 5,000				
			$ 22,000			$ 22,000			
			$ 2,000			$ 2,000			
			$ 3,000			$ 3,000			
			$ 7,000			$ 7,000			
			$ 107,000			$ 107,000			
			$ 8,000			$ 8,000			
			$ 45,000			$ 45,000			
			$ 13,000			$ 13,000			
			$ 7,000			$ 7,000			
			$ 7,000			$ 7,000			
			$ 5,000			$ 5,000			
			$ 11,000			$ 11,000			
			$ 12,000			$ 12,000			
			$ 384,000			$ 384,000			
		Subtotal 2011	**$ 1,225,830**						
			$ 8,500			$ 8,500			
			$ 10,000			$ 10,000			
			$ 18,000			$ 18,000			
			$ 13,000			$ 13,000			
			$ 21,000			$ 21,000			
			$ 9,000			$ 9,000			
			$ 40,000			$ 40,000			
			$ 30,000			$ 30,000			
			$ 32,500			$ 32,500			
			$ 2,000			$ 2,000			
			$ 15,000			$ 15,000			
	7/19/2012		$ 1,000				$ 1,000		
	7/31/2012		$ 9,000				$ 9,000		
	8/8/2012		$ 14,333				$ 14,333		
	8/20/2012		$ 8,000				$ 8,000		
	8/20/2012		$ 25,000				$ 25,000		
	8/20/2012		$ 50,000				$ 50,000		
	8/20/2012		$ 50,000				$ 50,000		
	9/17/2012		$ 14,000				$ 14,000		
	10/16/2012		$ 7,000				$ 7,000		
	11/30/2012		$ 7,000				$ 7,000		
	11/30/2012		$ 13,500				$ 13,500		
	12/21/2012		$ 17,000				$ 17,000		
	12/21/2012		$ 13,250				$ 13,250		
	12/21/2012		$ 13,250				$ 13,250		
	12/21/2012		$ 6,500				$ 6,500		
		Subtotal 2012	**$ 447,833**						
	1/30/2013		$ 6,000				$ 6,000		
	2/28/2013		$ 51,000				$ 51,000		
	2/28/2013		$ 10,000				$ 10,000		
	3/8/2013		$ 32,000				$ 32,000		
	4/29.2013		$ 30,000				$ 30,000		
	5/10/2013		$ 25,000				$ 25,000		
	6/4/2013		$ 10,000				$ 10,000		
	6/4/2013		$ 7,000				$ 7,000		
	7/10/2013		$ 137,000					$ 137,000	
	7/10/2013		$ 200,000					$ 200,000	
	9/3/2013		$ 9,000					$ 9,000	
	9/6/2013		$ 38,000					$ 38,000	
	10/1/2013		$ 12,000					$ 12,000	
	10/1/2013		$ 4,800					$ 4,800	
	10/1/2013		$ 15,000					$ 15,000	
	10/1/2013		$ 17,200					$ 17,200	
	10/1/2013		$ 12,000					$ 12,000	
	12/19/2013		$ 19,000					$ 19,000	
		Subtotal 2013	**$ 635,000**						
1/3/2014	1/15/2014		$ 19,500					$ 19,500	$ -
1/31/2014	2/3/2014		$ 10,750					$ 10,750	
5/30/2014	7/5/2014		$ 25,000						$ 25,000
8/4/2014	8/21/2014		$ 20,000						$ 20,000
8/4/2014	9/3/2014		$ 40,000						$ 40,000
9/2/2014	9/19/2014		$ 10,000						$ 10,000
10/31/2014	11/10/2014		$ 28,000						$ 28,000
12/2/2014	12/22/2014		$ 106,000						$ 106,000
12/2/2014	12/22/2014		$ 56,000						$ 56,000
		Subtotal 2014	**$ 315,250**						
			$ 2,623,913	**$ 20,000**	**$ 572,830**	**$ 832,000**	**$ 419,833**	**$ 494,250**	**$ 285,000**

Texas RE 2014 Penalties Reconciliation	12/31/2014	12/31/2013	Change in 2014
Total Cumulative Penalties - GAAP/BKD Audi	$ 2,623,913	$ 2,308,663	$ 315,250
Total Cumulative Penalties - True Up Report	$ 1,844,663	$ 1,424,830	$ 419,833
	$ 779,250	**$ 883,833**	**$ (104,583)**

Texas RE's auditted financial statements include penalties recorded as earned revenue at the time of invoicing, in accordance with GAAP.
Texas RE's true up report includes only those penalties included in the approved budget for the calendar year, as shown above.

Texas Reliability Entity, Inc.

Auditor's Report and Financial Statements

December 31, 2014 and 2013

BKD LLP
CPAs & Advisors

Texas Reliability Entity, Inc.

December 31, 2014 and 2013

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BKD LLP
CPAs & Advisors

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972.702.8262 // fax 972.702.0673 // bkd.com

Independent Auditor's Report

Board of Directors
Texas Reliability Entity, Inc.
Austin, Texas

We have audited the accompanying financial statements of Texas Reliability Entity, Inc. (Texas RE), which comprise the statements of financial position as of December 31, 2014 and 2013, and the related statements of activities and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Praxity MEMBER GLOBAL ALLIANCE OF INDEPENDENT FIRMS

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Texas Reliability Entity, Inc. as of December 31, 2014 and 2013, and the changes in its net assets and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements as a whole. The Schedule of Statutory and Nonstatutory Operating Activities and the Statutory and Nonstatutory Statement of Activity by Program are presented for purposes of additional analysis and are not a required part of the financial statements. Such information has not been subjected to the auditing procedures applied in the audit of the financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

BKD, LLP

Dallas, Texas
May 18, 2015

Texas Reliability Entity, Inc.
Statements of Financial Position
December 31, 2014 and 2013

Assets

	2014	2013
Current Assets		
Cash and cash equivalents	$ 6,117,540	$ 4,697,098
Assets limited to use – cash	694,332	887,078
	6,811,872	5,584,176
Accounts receivable	106,000	-
Other current assets	234,500	239,140
Total current assets	7,152,372	5,823,316
Property and Equipment, Net	455,373	602,903
Total assets	$ 7,607,745	$ 6,426,219

Liabilities and Net Assets

Current Liabilities		
Accounts payable	$ 196,154	$ 154,575
Accrued liabilities	507,747	349,460
Deferred rent	151,133	181,440
Total current liabilities	855,034	685,475
Unrestricted Net Assets		
Undesignated	6,058,379	4,853,666
Regulator designated	694,332	887,078
Total unrestricted net assets	6,752,711	5,740,744
Total liabilities and net assets	$ 7,607,745	$ 6,426,219

Texas Reliability Entity, Inc.

Statements of Activities

Years Ended December 31, 2014 and 2013

	2014	2013
Revenues, Gains and Other Support		
Statutory revenue		
Assessments	$ 10,509,308	$ 8,152,520
Penalty sanctions	315,250	635,000
Membership fees	19,500	19,250
Protocol revenue	970,000	1,029,100
Interest income	2,179	9,076
Total revenues, gains and other support	11,816,237	9,844,946
Expenses		
Salaries and related benefits	8,385,572	8,215,809
Facility and equipment costs	697,394	674,934
Outside services	734,570	854,729
Travel and meetings	342,916	359,880
Administrative and other	429,707	280,566
Depreciation	214,111	672,285
Total expenses	10,804,270	11,058,203
Change in Unrestricted Net Assets	1,011,967	(1,213,257)
Unrestricted Net Assets, Beginning of Year	5,740,744	6,954,001
Unrestricted Net Assets, End of Year	$ 6,752,711	$ 5,740,744

Texas Reliability Entity, Inc.

Statements of Cash Flows

Years Ended December 31, 2014 and 2013

	2014	2013
Operating Activities		
Change in net assets	$ 1,011,967	$ (1,213,257)
Item not requiring cash		
Depreciation	214,111	672,285
Changes in		
Accounts receivable	(106,000)	3,766
Other current assets	4,640	59,770
Accounts payable	41,579	(96,237)
Deferred rent	(30,307)	(22,548)
Accrued liabilities	158,287	(219,329)
Net cash provided by (used in) operating activities	1,294,277	(815,550)
Investing Activities		
Capital expenditures for property and equipment and systems under development	(66,581)	(83,411)
Net cash used in investing activities	(66,581)	(83,411)
Net Increase (Decrease) in Cash and Cash Equivalents	1,227,696	(898,961)
Cash, Beginning of Year	5,584,176	6,483,137
Cash and Cash Equivalents, End of Year	$ 6,811,872	$ 5,584,176

Texas Reliability Entity, Inc.

Notes to Financial Statements

December 31, 2014 and 2013

Note 1: Organization and Operations

Texas Reliability Entity, Inc. (Texas RE) is a Texas nonprofit corporation that is tax exempt under Section 501(c)(3) of the Internal Revenue Code. Texas RE was formed January 1, 2010, to be the Regional Entity for the Electric Reliability Council of Texas, Inc. (ERCOT) region and to preserve and enhance reliability across the ERCOT region by encouraging a culture of compliance among all users, owners and operators of the bulk-power system (BPS). Texas RE, took assignment of all rights, contracts, obligations, assets and liabilities of Texas Regional Entity (which was an independent division of ERCOT, the predecessor Regional Entity), effective midnight on June 30, 2010. Texas RE became the Regional Entity for the ERCOT region on July 1, 2010, pursuant to its Amended and Restated Delegation Agreement with North American Electric Reliability Corporation (NERC), which was approved by the Federal Energy Regulatory Commission (FERC) on May 6, 2010. The Delegation Agreement with NERC was further amended effective January 1, 2011 and October 7, 2011.

As Regional Entity, Texas RE proposes and facilitates development of new and modified NERC Reliability Standards and Regional Standards (Standards); monitors, assesses, investigates and enforces compliance by registered entities with Standards in the ERCOT region, and oversees the mitigation of any violations. Texas RE is authorized to impose penalties and sanctions for violations, but NERC and FERC must approve determination of all violations and the imposition of all penalties and sanctions. These Regional Entity activities are referred to herein as "statutory" activities.

The ERCOT region is the geographic area located within the state of Texas that operates under the jurisdiction of the Public Utility Commission of Texas (PUCT) and is not synchronously interconnected with any electric utilities operating outside of Texas. The ERCOT region includes approximately 200,000 square miles and 85% of Texas load.

In addition to Texas RE's statutory activities as Regional Entity, Texas RE has a contract with the PUCT and ERCOT to be the Reliability Monitor for the ERCOT region. As Reliability Monitor, Texas RE monitors, investigates and reports to the PUCT regarding compliance with state reliability rules (the reliability-based ERCOT Protocols and Operating Guides), and coordinates and assists PUCT staff with related reliability-related matters. The PUCT is responsible for the enforcement of violations of the state reliability rules. Texas RE's activities under this contract are permitted by NERC and FERC, by Exhibit E to the Delegation Agreement, and these activities are referred to herein as "nonstatutory" activities.

Texas Reliability Entity, Inc.
Notes to Financial Statements
December 31, 2014 and 2013

Membership and Governance

Texas RE has the following six membership sectors under its Bylaws:

- System Coordination and Planning: An entity that is registered with NERC as a Reliability Coordinator (RC), Balancing Authority (BA), Planning Authority (PA), Resource Planner (RP) or Interchange Authority (IA).

- Transmission and Distribution: An entity that is registered with NERC as a Transmission Owner (TO), Transmission Planner (TP), Transmission Service Provider (TSP), Distribution Provider (DP), and/or Transmission Operator (TOP) and is not a Cooperative or Municipal Utility.

- Cooperative Utility: An entity that is (a) a corporation organized under Chapter 161 of the Texas Utilities Code or a predecessor statute to Chapter 161 and operating under that chapter; (b) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct affairs in the state of Texas or (c) a cooperative association organized under Tex. Rev. Civ. Stat. 1396-50.01 or a predecessor to that statute and operating under that statute that is registered with NERC for at least one reliability function.

- Municipal Utility: An entity that owns or controls transmission or distribution facilities, owns or controls dispatchable generating facilities or provides retail electric service and is a municipally owned utility as defined in PURA §11.003 and is registered with NERC for at least one reliability function.

- Generation: An entity that is registered with NERC as a Generator Owner (GO) or Generator Operator (GOP).

- Load-Serving and Marketing: An entity that is registered with NERC as a Load-Serving Entity (LSE), a Purchasing-Selling Entity (PSE) or any newly defined NERC reliability function for demand response.

Membership in Texas RE is voluntary and open to any entity that is a user, owner or operator of the ERCOT region BPS and registered with NERC for at least one reliability function. Eligible registered entities must complete and submit a membership application, pay a nominal annual fee, which may be waived for good cause shown and comply with the Texas RE Bylaws. Any person or entity that has a direct and material interest in the BPS has a right to participate in the Texas RE Standards development process, even if not a Texas RE member.

Texas RE is governed by a hybrid board of directors (the Board), comprised of the following nine directors:

- Texas RE President and Chief Executive Officer
- Four Independent Directors
- Two Member Directors (the Chair and Vice-Chair of the Member Representatives Committee)
- Chair of the PUCT, or another PUCT Commissioner designated by the Chairman, as an ex officio nonvoting member
- Texas Public Counsel, from the Texas Office of Public Utility Counsel, as an ex officio nonvoting member

The Board's primary role is to oversee management of Texas RE, including assuring that Texas RE meets its requirements under the Bylaws and Delegation Agreement, and to elect a Chief Executive Officer to manage and be responsible for the day-to-day ongoing activities of Texas RE. The Board has one subcommittee, the Audit and Governance Committee, which is comprised of the Independent Directors.

Texas RE has two stakeholder committees, the Member Representatives Committee (MRC) and the Reliability Standards Committee (RSC). The MRC includes representatives from members in each of the six membership sectors and provides advice and recommendations to the Board on administrative, financial, reliability-related or any other matters, except for Standards development issues, through its elected Chair and Vice-Chair, who serve as directors. The RSC includes representatives from the six industry sectors described above, whether or not members of Texas RE and including any entity with a direct and material interest in the ERCOT region BPS. The RSC facilitates the Regional Standards development process, coordinates the development of Regional Standards and variances with the development of national NERC Standards, and monitors, reviews, and comments on Standards under development and Standards interpretation requests.

Note 2: Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses gains, losses and other changes in net assets during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Texas RE considers all liquid investments with original maturities of three months or less to be cash equivalents. At December 31, 2014, cash equivalents consisted of a sweep account with a financial institution. Texas RE had no cash equivalents at December 31, 2013.

At December 31, 2014, Texas RE's cash accounts, excluding its sweep account that had a balance of $4,000,000, exceeded federally insured limits by approximately $2,600,000. Texas RE places its cash with a high quality financial institution, and management believes no significant risks exist with respect to uninsured balances.

Assets Limited to Use

As stipulated by NERC policies, Texas RE records fines and penalties that are required to be used in future operations as assets limited to use. Assets limited to use (maintained in a financial institution) were $694,332 and $887,078 at December 31, 2014 and 2013, respectively.

Revenue Recognition

Texas RE funds its statutory operations primarily from assessments NERC collects from load serving entities and pays to Texas RE in four quarterly payments, pursuant to the Delegation Agreement. All statutory budgeted expenditures for Texas RE are approved by the Texas RE Board when it approves Texas RE's annual business plan and budget.

Texas RE funds its nonstatutory operations from revenues paid by ERCOT from its PUCT approved system administration fee, pursuant to the Reliability Monitor Agreement. All nonstatutory budgeted expenditures for Texas RE are approved by the Texas RE Board when it approves Texas RE's annual business plan and budget.

Texas RE recognizes revenue related to fines and penalties in the period in which they are earned (all appeals have been exhausted).

Related Party Transactions

Texas RE compensates its independent board directors, which is a common practice in the industry in which Texas RE operates. The authority to compensate its independent board directors is specified in the Bylaws, which were approved by the Texas RE membership. Texas RE independent board director compensation (totaling approximately $233,000 during 2014 and $225,000 during 2013) is paid monthly. In addition to their compensation, Texas RE independent board members are reimbursed for their actual expenses incurred related to their duties as a Texas RE independent board member.

Property and Equipment

Property and equipment are stated at cost less accumulated depreciation and amortization. Depreciation is charged to expense using the straight-line method over the estimated useful life of each asset. Assets under capital lease obligations and leasehold improvements are amortized over the shorter of the lease term or their respective estimated useful lives. Repairs and maintenance costs are expensed when incurred.

The estimated useful lives for each major depreciable classification of property and equipment are as follows:

Equipment	5 years
Computer hardware	3 years
Computer software	5 years
Furniture and fixtures	7 years
Leasehold improvements	7.5 years

Long-lived Asset Impairment

Texas RE evaluates the recoverability of the carrying value of long-lived assets whenever events or circumstances indicate the carrying amount may not be recoverable. If a long-lived asset is tested for recoverability and the undiscounted estimated future cash flows expected to result from the use and eventual disposition of the asset is less than the carrying amount of the asset, the asset cost is adjusted to fair value and an impairment loss is recognized as the amount by which the carrying amount of a long-lived asset exceeds it fair value. No asset impairment was recognized during the years ended December 31, 2014 and 2013.

Deferred Rent

In 2010, Texas RE entered into an operating lease agreement, which contains provisions for future increases in rent payments. In accordance with accounting principles generally accepted in the United States of America, Texas RE records monthly rent expense equal to the total of payments due over the lease term divided by the number of months of the lease term. The difference between rent expense recorded and the amount paid is credited or charged to deferred rent.

Income Taxes

Texas RE is exempt from income taxes under Section 501 of the Internal Revenue Code and a similar provision of state law. However, Texas RE is subject to federal income tax on any unrelated business taxable income.

Texas RE files tax returns in the U.S. federal jurisdiction. With a few exceptions, Texas RE is no longer subject to U.S. federal examinations by tax authorities for years before 2011.

Note 3: Expenses by Functional Classification

While the statements of activities presents expenses by natural classification, Texas RE's expenses by functional classification for the years ended December 31 were as follows:

	2014	2013
Program	$ 6,782,772	$ 6,942,188
General and administrative	4,021,498	4,116,015
Total	$ 10,804,270	$ 11,058,203

Certain costs have been allocated among the program and general and management categories based on actual use or estimates made by management.

Note 4: Property and Equipment

Property and equipment at December 31 consists of:

	2014	2013
Equipment	$ 410,886	$ 410,886
Computer hardware	732,040	701,980
Computer software	1,376,992	1,376,992
Furniture	309,512	309,512
Leasehold improvement	206,521	206,521
Work in process	51,520	15,000
Total property and equipment	3,087,471	3,020,891
Less accumulated depreciation	2,632,098	2,417,988
Total property and equipment, net	$ 455,373	$ 602,903

Note 5: Line of Credit

On March 27, 2014, Texas RE renewed the $500,000 bank line of credit originally obtained on January 29, 2013, which is now set to expire in April 2015. The line of credit is unsecured. Interest rate varies with LIBOR plus 4.260%. At December 31, 2014 and 2013, there were no borrowings against the line of credit.

Note 6: Operating Leases

Texas RE leases office space, datacenter space and equipment under noncancellable agreements recorded as operating leases. Operating lease expenditures for the year ended December 31, 2014, were $479,711. The future rental payments due under operating leases are as follows:

2015	$ 661,154
2016	793,983
2017	695,265
2018	569,111
2019	616,985
Thereafter	414,522
	$ 3,751,020

Note 7: Employee Benefit Plans

Texas RE employees are sponsored under the Texas Reliability Entity, Inc. 401(k) Savings Plan (Plan) which is subject to the provisions of the Employee Retirement Income Security Act of 1974. The Plan utilizes a third-party administrator to assist in the administration. Employees must be 21 years of age to be eligible to participate. Texas RE matches 75% of the employee's contribution up to 6% of eligible compensation as defined in the plan document. Employees are fully vested for the Texas RE match of 75% after five years. In addition, Texas RE contributes 10% of a participant's eligible compensation as defined in the plan document. Employees are fully vested for the Texas RE contributions of 10% after three years. Employer contributions to the 401(k) plan were $659,577 and $813,224, respectively, in 2014 and 2013.

Note 8: Subsequent Events

Subsequent events have been evaluated through the date of the Independent Auditor's Report, which is the date the financial statements were available to be issued.

Other Information

Texas Reliability Entity, Inc.

Schedule of Statutory and Nonstatutory Operating Activities

Year Ended December 31, 2014

	Statutory	Nonstatutory	Total
Revenues, Gains and Other Support			
Statutory revenue	$ 10,844,058	$ -	$ 10,844,058
Protocol revenue	-	970,000	970,000
Interest income	1,846	333	2,179
Total revenues, gains and other support	10,845,904	970,333	11,816,237
Expenses			
Salaries and related benefits	7,683,804	701,768	8,385,572
Facility and equipment costs	658,834	38,560	697,394
Outside services	725,413	9,157	734,570
Travel and meetings	342,816	100	342,916
Administrative and other	420,845	8,862	429,707
Depreciation	162,496	51,615	214,111
Total expenses	9,994,208	810,062	10,804,270
Change in Unrestricted Net Assets	851,696	160,271	1,011,967
Unrestricted Net Assets, Beginning of Year	4,958,313	782,431	5,740,744
Unrestricted Net Assets, End of Year	$ 5,810,009	$ 942,702	$ 6,752,711

Texas Reliability Entity, Inc.

Statutory and Nonstatutory Statement of Activity by Program

Year Ended December 31, 2014

	Reliability Standards	CMEP	Reliability Assessment and Performance Analysis/SAIS	Training and Education & Member Services	General and Administrative	Legal and Regulatory	Information Technology	Human Resources	Accounting and Finance	Statutory Total	State (Nonstatutory) Total	Total
Funding												
Assessments	$ 433,387	$ 8,994,237	$ 1,545,048	$ 377,493	$ (840,857)	$ -	$ -	$ -	$ -	$ 10,509,308	$ -	$ 10,509,308
Penalty sanctions	12,800	256,040	35,205	11,205	-	-	-	-	-	315,250	-	315,250
Membership fees	792	15,837	2,178	693	-	-	-	-	-	19,500	-	19,500
Testing fees	-	-	-	-	-	-	-	-	-	-	970,000	970,000
Interest income	75	1,500	206	65	-	-	-	-	-	1,846	333	2,179
Total funding	447,054	9,267,614	1,582,637	389,456	(840,857)	-	-	-	-	10,845,904	970,333	11,816,237
Expenses												
Personnel expenses												
Salaries	236,969	3,211,066	812,342	152,475	481,035	295,823	325,621	85,479	285,797	5,886,607	568,419	6,455,026
Payroll taxes	16,668	233,992	57,453	10,136	11,617	22,302	23,823	6,171	20,601	402,763	39,946	442,709
Employee benefits	28,585	419,915	110,926	25,866	4,364	40,509	104,939	24,728	43,257	803,089	25,170	828,259
Savings and retirement	24,267	320,462	84,930	15,395	44,398	27,178	35,793	9,333	29,589	591,345	68,233	659,578
Total personnel expenses	306,489	4,185,435	1,065,651	203,872	541,414	385,812	490,176	125,711	379,244	7,683,804	701,768	8,385,572
Meeting and travel expenses												
Meetings	264	1,853	658	16,339	12,855	-	224	6,721	-	38,914	-	38,914
Travel	13,142	124,915	59,392	5,554	68,878	8,996	7,923	4,084	2,316	295,200	100	295,300
Conference expenses	-	-	-	6,380	-	-	2,322	-	-	8,702	-	8,702
Total meeting and travel expenses	13,406	126,768	60,050	28,273	81,733	8,996	10,469	10,805	2,316	342,816	100	342,916
Operating expenses												
Consultants and contracts	350	146,808	1,050	-	53,033	4,700	32,879	78,727	174	317,721	2,107	319,828
Rent and improvements	-	-	-	-	483,548	-	6,364	-	-	489,912	25,945	515,857
Office costs	232	13,893	30,790	2,164	70,262	2,686	426,837	6,103	22,971	575,938	19,955	595,893
Professional services	-	240	-	-	249,850	17,326	71,712	-	82,393	421,521	8,572	430,093
Depreciation	-	-	-	-	162,496	-	-	-	-	162,496	51,615	214,111
Total operating expenses	582	160,941	31,840	2,164	1,019,189	24,712	537,792	84,830	105,538	1,967,588	108,194	2,075,782
Total expenses	320,477	4,473,144	1,157,541	234,309	1,642,336	419,520	1,038,437	221,346	487,098	9,994,208	810,062	10,804,270
Change in Unrestricted Net Assets	$ 126,577	$ 4,794,470	$ 425,096	$ 155,147	$ (2,483,193)	$ (419,520)	$(1,038,437)	$ (221,346)	$ (487,098)	$ 851,696	$ 160,271	$ 1,011,967

ATTACHMENT 9

2014 ACTUAL COST-TO-BUDGET COMPARISON

(BASED ON UNAUDITED FINANCIAL STATEMENTS)

FOR

WESTERN ELECTRICITY COORDINATING COUNCIL

2014 Unaudited Statement of Activities and Variance Explanations

Western Electricity Coordinating Council

155 North 400 West, Suite 200
Salt Lake City, Utah 84103-1114

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Overview

Summary

The Western Electricity Coordinating Council's (WECC) unaudited change in statutory working capital for the year ended December 31, 2014 is under budget by $212,000 with grant activity and $321,000 under budget without grant activity. The major drivers of WECC's net 2014 underrun are related to:

- An underrun of approximately $950,000 related to consulting expenses for the Regional Transmission Expansion Planning project grant due to the use of staff for projects as opposed to higher-priced consultants;
- An overrun of $875,000 in Personnel Expenses related to labor float rate assumptions, an unbudgeted increase in WECC's defined-contribution percentage, and lower-than-budgeted enrollment in WECC's benefits plans;
- An underrun of $350,000 related to delayed deliverables on RAS Modeling contracts;
- An underrun of $392,000 in Travel Expenses primarily due to a $321,000 decrease as a result of risk-based compliance monitoring, $46,000 for budgeted travel within Technical Committees and Member Forums but expensed within RAPA as well as department-wide cost-saving efforts;
- An underrun of $286,000 in benefits primarily due to less-than-anticipated enrollment in insurance programs by employees;
- An underrun of $193,000 in Meeting Expenses mainly due to holding all Board of Directors meetings in the WECC meeting space;
- An overrun of approximately $594,000 in Professional Services related to unanticipated legal fees and the restructuring of Board Director compensation.

This document provides a summary of significant overall variances (greater than $10,000 and 10 percent). For significant Program Area line-item variances, see the detailed statements of activities for each Program Area.

WECC substantially completed all of its goals and key deliverables as contained in the 2014 Business Plan and Budget except for the implementation of the Base Case Coordination System (BCCS). The BCCS implementation extended into 2015 due to software vendor delays.

Allocation of Indirect Costs

Administrative Services costs are allocated to program activities based on a full-time equivalent (FTE) ratio that is consistent with North American Electric Reliability Corporation's (NERC) accounting methodology for allocation of overhead.

Federal Grants

In WECC's 2010 Amended Business Plan and Budget, WECC included revenue and associated costs related to three U.S. Department of Energy grants. FERC determined that the activities performed under the three grants received by WECC qualified as Section 215 activities.

One grant, the Regional Transmission Expansion Project (RTEP), remains in WECC's 2014 Business Plan and Budget. This grant ended in 2014.

The RTEP project, which encompasses all activities funded under this U.S. DOE grant, produces Interconnection-level transmission plans for the Western Interconnection.

RTEP is a natural expansion of the depth, breadth, and coordination of existing regional and subregional planning processes. The project plan accomplishes the following:

- Evaluates the long-term regional transmission capacity needs under a comprehensive set of load, resource, and policy scenarios.
- Incorporates the results of a comprehensive examination of reliability impacts, technology costs, and emissions conducted during the project.
- Provides guidance for decision-makers at all levels (project developers, siting authorities, utility regulators, etc.).
- Facilitates and accelerates the development of needed transmission infrastructure.

WECC uses a fund-accounting system to ensure that federal grant activities are segregated in accordance with federal cost-accounting standards.

Non-Statutory

WECC has one non-statutory activity, the Western Renewable Energy Generation Information System (WREGIS). WECC uses a fund-accounting system that allows costs to be segregated between statutory and non-statutory activities to ensure that no statutory funding is used for non-statutory activities.

In 2014, WECC allocated indirect costs to its non-statutory activity based on FTEs. Indirect costs include the Board of Directors, General and Administrative, Legal, Information Technology, Human Resources, and Finance programs. These costs are allocated to WREGIS based on the ratio of total WREGIS FTEs to total operating program FTEs. The allocation is consistent with the FTE method of allocating overhead costs used by NERC and the other Regional Entities.

Reserves

In 2014, WECC budgeted $2.4 million of working capital reserves to offset the large increase in assessments. WECC used $2.2 million of working capital reserves to offset 2014 statutory assessments.

2014 Unaudited Statement of Activities – Statutory and Non-Statutory

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Statutory and Non-Statutory

	2014 Actual	2014 Budget	2014 Variance Over(Under)
Funding			
WECC Funding			
WECC Assessments	$ 15,630,852	$ 15,630,852	$ -
Penalty Sanctions	2,933,050	2,933,050	-
Total ERO Funding	**$ 18,563,902**	**$ 18,563,902**	**$ -**
Membership Fees	3,022,447	1,896,000	1,126,447
Grant Funding	3,638,249	3,628,308	9,941
Services & Software	-	-	-
Workshops	951,969	965,729	(13,760)
Interest	108,429	69,000	39,429
Miscellaneous	-	-	-
Total Funding	**$ 26,284,996**	**$ 25,122,939**	**$ 1,162,057**
Expenses			
Personnel Expenses			
Salaries	13,085,114	12,446,955	638,159
Payroll Taxes	914,498	797,716	116,782
Employee Benefits	1,873,676	2,195,679	(322,003)
Savings & Retirement	1,133,172	797,716	335,456
Total Personnel Expenses	**$ 17,006,460**	**$ 16,238,065**	**$ 768,395**
Meeting Expenses			
Meetings	681,591	886,701	(205,110)
Travel	1,098,517	1,545,456	(446,939)
Conference Calls	71,230	114,222	(42,992)
Total Meeting Expenses	**$ 1,851,338**	**$ 2,546,379**	**$ (695,041)**
Operating Expenses			
Consultants & Contracts	3,020,841	4,393,302	(1,372,461)
Office Rent	948,561	936,072	12,489
Office Costs	1,903,634	1,962,504	(58,870)
Professional Services	1,367,987	775,256	592,731
Miscellaneous	-	-	-
Depreciation	645,784	580,000	65,784
Total Operating Expenses	**$ 7,886,807**	**$ 8,647,134**	**$ (760,327)**
Total Direct Expenses	**$ 26,744,605**	**$ 27,431,578**	**$ (686,973)**
Indirect Expenses	0	-	-
Other Non-Operating Expenses	**$ 31,207**	**$ -**	**$ 31,207**
Total Expenses	**26,775,812**	**27,431,578**	**(655,766)**
Change in Assets	**$ (490,816)**	**$ (2,308,640)**	**$ 1,817,823**
Fixed Assets			
Depreciation	(645,784)	(580,000)	(65,784)
Computer & Software CapEx	499,895	309,487	190,408
Furniture & Fixtures CapEx	-	-	-
Equipment CapEx	48,359	136,000	(87,641)
Leasehold Improvements	7,647	-	7,647
Allocation of Fixed Assets	(0)	-	(0)
Incr(Dec) in Fixed Assets	**$ (89,883)**	**$ (134,513)**	**$ 44,630**
Total Budget	**26,685,929**	**27,297,065**	**(611,136)**
Change in Working Capital	**$ (400,933)**	**$ (2,174,126)**	**$ 1,773,193**
FTEs	121.8	140.0	(18.2)
Headcount	127.0	140.0	(13.0)

2014 Unaudited Statement of Activities – Statutory

Western Electricity Coordinating Council 2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital Statutory Summary	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ 15,630,852	15,630,852	$ -	0.0%
Penalty Sanctions	2,933,050	2,933,050	-	0.0%
Total ERO Funding	**$ 18,563,902**	**$ 18,563,902**	**$ -**	0.0%
Membership Fees	-	-	-	
Grant Funding	3,638,249	3,628,308	9,941	0.3%
Services & Software	-	-	-	
Workshops	950,259	957,929	(7,670)	-0.8%
Interest	79,104	69,000	10,104	14.6%
Miscellaneous	-	-	-	
Total Funding	**$ 23,231,514**	**$ 23,219,138**	**$ 12,375**	0.1%
Expenses				
Personnel Expenses				
Salaries	12,804,260	12,096,225	708,035	5.9%
Payroll Taxes	892,198	774,001	118,197	15.3%
Employee Benefits	1,843,630	2,129,744	(286,114)	-13.4%
Savings & Retirement	1,108,576	774,001	334,575	43.2%
Total Personnel Expenses	**$ 16,648,664**	**$ 15,773,971**	**$ 874,693**	5.5%
Meeting Expenses				
Meetings	680,153	873,476	(193,323)	-22.1%
Travel	1,092,099	1,484,456	(392,357)	-26.4%
Conference Calls	70,344	114,222	(43,878)	-38.4%
Total Meeting Expenses	**$ 1,842,596**	**$ 2,472,154**	**$ (629,558)**	-25.5%
Operating Expenses				
Consultants & Contracts	3,019,246	4,387,302	(1,368,056)	-31.2%
Office Rent	948,495	936,072	12,423	1.3%
Office Costs	1,452,027	1,405,454	46,573	3.3%
Professional Services	1,367,987	758,756	609,231	80.3%
Miscellaneous	-	-	-	
Depreciation	645,784	580,000	65,784	11.3%
Total Operating Expenses	**$ 7,433,539**	**$ 8,067,584**	**$ (634,045)**	-7.9%
Total Direct Expenses	**$ 25,924,799**	**$ 26,313,708**	**$ (388,910)**	-1.5%
Indirect Expenses	(409,077)	(541,111)	132,034	-24.4%
Other Non-Operating Expenses	**$ 12,207**	**$ -**	**$ 12,207**	
Total Expenses	**25,527,929**	**25,772,597**	**(244,669)**	-0.9%
Change in Assets	**$ (2,296,415)**	**$ (2,553,459)**	**$ 257,044**	-10.1%
Fixed Assets				
Depreciation	(645,784)	(580,000)	(65,784)	11.3%
Computer & Software CapEx	499,895	309,487	190,408	61.5%
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	48,359	136,000	(87,641)	-64.4%
Leasehold Improvements	7,647	-	7,647	
Allocation of Fixed Assets	(0)	-	(0)	
Incr(Dec) in Fixed Assets	**$ (89,883)**	**$ (134,513)**	**$ 44,630**	-33.2%
Total Budget	**25,438,046**	**25,638,084**	**(200,039)**	-0.8%
Change in Working Capital	**$ (2,206,530)**	**$ (2,418,946)**	**$ 212,414**	-8.8%
FTEs	117.8	135.0	(17.2)	
Headcount	123.0	135.0	(12.0)	

2014 Unaudited Statement of Activities – Statutory Without Federal Grants

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Statutory Summary Without Grants

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ 15,630,852	15,630,852	$ (0)	0.0%
Penalty Sanctions	2,933,050	2,933,050	-	0.0%
Total ERO Funding	**$ 18,563,902**	**$ 18,563,902**	**$ (0)**	0.0%
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software	-	-	-	
Workshops	950,259	957,929	(7,670)	-0.8%
Interest	79,104	69,000	10,104	14.6%
Miscellaneous	-	-	-	
Total Funding	**$ 19,593,265**	**$ 19,590,830**	**$ 2,434**	0.0%
Expenses				
Personnel Expenses				
Salaries	12,117,190	11,667,376	449,814	3.9%
Payroll Taxes	843,625	746,634	96,991	13.0%
Employee Benefits	1,774,309	2,068,607	(294,298)	-14.2%
Savings & Retirement	1,047,467	746,634	300,833	40.3%
Total Personnel Expenses	**$ 15,782,591**	**$ 15,229,251**	**$ 553,340**	3.6%
Meeting Expenses				
Meetings	661,319	863,476	(202,157)	-23.4%
Travel	1,066,933	1,454,456	(387,523)	-26.6%
Conference Calls	60,849	108,222	(47,373)	-43.8%
Total Meeting Expenses	**$ 1,789,101**	**$ 2,426,154**	**$ (637,053)**	-26.3%
Operating Expenses				
Consultants & Contracts	1,121,777	1,587,302	(465,525)	-29.3%
Office Rent	948,495	936,072	12,423	1.3%
Office Costs	1,227,038	1,341,354	(114,316)	-8.5%
Professional Services	1,364,738	758,756	605,982	79.9%
Miscellaneous	-	-	-	
Depreciation	474,795	481,000	(6,205)	-1.3%
Total Operating Expenses	**$ 5,136,843**	**$ 5,104,484**	**$ 32,359**	0.6%
Total Direct Expenses	**$ 22,708,535**	**$ 22,759,888**	**$ (51,354)**	-0.2%
Indirect Expenses	(409,077)	(541,111)	132,034	-24.4%
Other Non-Operating Expenses	**$ 12,207**	**$ -**	**$ 12,207**	
Total Expenses	**22,311,665**	**22,218,777**	**92,887**	0.4%
Change in Assets	**$ (2,718,400)**	**$ (2,627,946)**	**$ (90,454)**	3.4%
Fixed Assets				
Depreciation	(474,795)	(481,000)	6,205	-1.3%
Computer & Software CapEx	(28,608)	309,487	(338,095)	-109.2%
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	48,359	136,000	(87,641)	-64.4%
Leasehold Improvements	7,647	-	7,647	
Allocation of Fixed Assets	(0)	-	(0)	
Incr(Dec) in Fixed Assets	**$ (447,397)**	**$ (35,513)**	**$ (411,884)**	1159.8%
Total Budget	**21,864,268**	**22,183,264**	**(318,997)**	-1.4%
Change in Working Capital	**$ (2,271,001)**	**$ (2,592,433)**	**$ 321,430**	-12.4%
FTEs	117.8	135.0	(17.2)	
Headcount	123.0	135.0	(12.0)	

Significant Variance Explanations – Statutory Activities

Funding

- Interest Income: $10,000 over budget
    - WECC earned higher-than-anticipated rates of return on cash balances.

Expenses

- Salaries: $708,000 over budget
    - WECC's budgeted labor float rate assumptions were greater than actual vacancy rates.
- Payroll Taxes: $118,000 over budget
    - WECC's budgeted labor float rate assumptions were greater than actual vacancy rates.
- Employee Benefits: $286,000 under budget
    - Enrollment in benefit plans was lower than anticipated among existing employees.
    - Employee training needs were less than anticipated.
- Savings and Retirement: $335,000 over budget
    - WECC's Board increased the defined-contribution percentage after the 2014 budget was approved.
    - WECC's budgeted labor float rate assumptions were greater than actual vacancy rates.
- Meetings: $193,000 under budget
    - Staff increased use of webinars where feasible to minimize in-person meeting costs.
    - The June Annual Member and Board of Directors Meetings were held in the WECC meeting space and were originally budgeted to be held offsite.
- Travel: $392,000 under budget
    - WECC staff attended fewer off-site meetings and increased meeting attendance via webinar where feasible.
    - WECC instituted company-wide cost-saving efforts to reduce expenses.
- Conference Calls: $44,000 under budget
    - Conference call usage was less than expected.
- Consultants & Contracts: $1.37 million under budget
    - Deliverables on a RAS modeling contract were delayed.
    - WECC used staff for some RTEP projects to minimize the cost of higher-priced consultants and maximize grant spending on other allowable costs.
    - Some smaller variances are related to classification issues between Operating Expenses and Fixed Assets.
- Professional Services: $609,000 over budget
    - WECC incurred legal fees during 2014 related to unanticipated litigation.
    - Independent Board member compensation was restructured after the 2014 budget was approved.

- Indirect Expenses: $132,000 under budget
    - The indirect allocation is driven by the headcount in the Western Regional Energy Information Generation System (WREGIS) Department where four of the five budgeted positions were filled in 2014.

Fixed Assets

- Computer and Software CapEx: $190,000 over budget
    - Variance is related to classification issues between Operating Expenses and Fixed Assets.
- Equipment CapEx: $88,000 under budget
    - Variance is related to classification issues between Operating Expenses and Fixed Assets.

Section A
Statutory Programs

2014 Unaudited Statements of Activities and Variance Explanations

Reliability Standards Program

Western Electricity Coordinating Council 2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital Reliability Standards	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ 790,180	$ 790,180	$ -	0.0%
Penalty Sanctions	133,169	133,169	-	0.0%
Total ERO Funding	**$ 923,349**	**$ 923,349**	**$ -**	0.0%
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	-	-	-	
Interest	2,984	3,133	(149)	-4.8%
Miscellaneous	-	-	-	
Total Funding	**$ 926,333**	**$ 926,482**	**$ (149)**	0.0%
Expenses				
Personnel Expenses				
Salaries	430,402	447,768	(17,366)	-3.9%
Payroll Taxes	29,986	30,138	(152)	-0.5%
Employee Benefits	29,960	48,499	(18,539)	-38.2%
Savings & Retirement	38,508	30,138	8,370	27.8%
Total Personnel Expenses	**$ 528,856**	**$ 556,544**	**$ (27,688)**	-5.0%
Meeting Expenses				
Meetings	-	528	(528)	-100.0%
Travel	18,951	28,360	(9,409)	-33.2%
Conference Calls	2,441	4,188	(1,747)	-41.7%
Total Meeting Expenses	**$ 21,392**	**$ 33,076**	**$ (11,684)**	-35.3%
Operating Expenses				
Consultants & Contracts	-	-	-	
Office Rent	-	-	-	
Office Costs	5,895	8,120	(2,225)	-27.4%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ 5,895**	**$ 8,120**	**$ (2,225)**	-27.4%
Total Direct Expenses	**$ 556,143**	**$ 597,740**	**$ (41,597)**	-7.0%
Indirect Expenses	345,562	432,890	(87,328)	-20.2%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**901,705**	**1,030,630**	**(128,925)**	-12.5%
Change in Assets	**$ 24,628**	**$ (104,148)**	**$ 128,776**	-123.6%
Fixed Assets				
Depreciation	-		-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	(5,464)	(7,628)	2,164	-28.4%
Incr(Dec) in Fixed Assets	**$ (5,464)**	**$ (7,628)**	**$ 2,164**	-28.4%
Total Budget	**896,241**	**1,023,002**	**(126,761)**	-12.4%
Change in Working Capital	**$ 30,092**	**$ (96,520)**	**$ 126,612**	-131.2%
FTEs	3.0	4.0	(1.0)	
Headcount	3.0	4.0	(1.0)	

Significant Variance Explanations – Reliability Standards Program

Personnel Expenses

- Personnel Expenses are $28,000 under budget due to an unfilled position.

Meeting Expenses

- Not applicable.

Operating Expenses

- Not applicable.

Indirect Expenses

- Indirect Expenses are under budget by $87,000 due to the unfilled position in Standards and the unfilled position in WREGIS. WECC's indirect allocation is based on actual FTEs in each Program Area.

Fixed Assets

- Not applicable.

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Compliance Monitoring and Enforcement and Organization Registration and Certification

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ 10,955,928	$ 10,955,928	$ -	0.0%
Penalty Sanctions	1,930,952	1,930,952	-	0.0%
Total ERO Funding	**$ 12,886,880**	**$ 12,886,880**	**$ -**	0.0%
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	563,879	438,125	125,754	28.7%
Interest	48,534	45,426	3,108	6.8%
Miscellaneous	-	-	-	
Total Funding	**$ 13,499,293**	**$ 13,370,431**	**$ 128,862**	1.0%
Expenses				
Personnel Expenses				
Salaries	4,972,400	4,769,767	202,633	4.2%
Payroll Taxes	375,142	322,315	52,827	16.4%
Employee Benefits	631,996	795,563	(163,567)	-20.6%
Savings & Retirement	424,499	322,315	102,184	31.7%
Total Personnel Expenses	**$ 6,404,037**	**$ 6,209,960**	**$ 194,077**	3.1%
Meeting Expenses				
Meetings	471,531	462,503	9,028	2.0%
Travel	645,021	966,340	(321,319)	-33.3%
Conference Calls	19,915	41,780	(21,865)	-52.3%
Total Meeting Expenses	**$ 1,136,467**	**$ 1,470,623**	**$ (334,156)**	-22.7%
Operating Expenses				
Consultants & Contracts	595,631	424,800	170,831	40.2%
Office Rent	1,407	-	1,407	
Office Costs	360,102	450,670	(90,568)	-20.1%
Professional Services	5,245	-	5,245	
Miscellaneous	-	-	-	
Depreciation	25,186	36,000	(10,814)	-30.0%
Total Operating Expenses	**$ 987,571**	**$ 911,470**	**$ 76,101**	8.3%
Total Direct Expenses	**$ 8,528,075**	**$ 8,592,053**	**$ (63,978)**	-0.7%
Indirect Expenses	5,620,295	6,276,897	(656,602)	-10.5%
Other Non-Operating Expenses	**$ 3,319**	**$ -**	**$ 3,319**	
Total Expenses	**14,151,689**	**14,868,950**	**(717,261)**	-4.8%
Change in Assets	**$ (652,396)**	**$ (1,498,519)**	**$ 846,123**	-56.5%
Fixed Assets				
Depreciation	(25,186)	(36,000)	10,814	-30.0%
Computer & Software CapEx	-	10,000	(10,000)	-100.0%
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	31,000	(31,000)	-100.0%
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	(88,862)	(110,602)	21,740	-19.7%
Incr(Dec) in Fixed Assets	**$ (114,048)**	**$ (105,602)**	**$ (8,446)**	8.0%
Total Budget	**14,037,641**	**14,763,348**	**(725,707)**	-4.9%
Change in Working Capital	**$ (538,348)**	**$ (1,392,917)**	**$ 854,569**	-61.4%
FTEs	48.6	58.0	(9.4)	
Headcount	51.0	58.0	(7.0)	

Significant Variance Explanations – Compliance Monitoring and Enforcement

Funding

- Workshop revenue is over budget by $126,000 due to higher-than-anticipated registration for WECC workshops.

Personnel Expenses

- Salaries are over budget by $203,000 due to WECC's budgeted labor float rate assumptions compared with actual vacancy rates and incentives that were budgeted in General and Administrative.
- Payroll Taxes are $53,000 over budget due to WECC's budgeted labor float rate assumptions compared with actual vacancy rates.
- Employee Benefits are $164,000 under budget due to lower-than-anticipated plan enrollment among existing employees and under-utilization of training.
- Savings and Retirement are $102,000 over budget due to an unanticipated increase in the defined-contribution percentage and WECC's labor float assumptions.

Meeting Expenses

- Travel Expenses are $321,000 under budget due to travel reductions as a result of risk-based compliance monitoring, department-wide cost-saving efforts, and budget-classification issues related to consultant travel expenditures.
- Conference Calls are $22,000 under budget due less-than-anticipated usage.

Operating Expenses

- Consultants and Contracts are $171,000 over budget due to the budget for the compliance WebCDMS tool originally being classified in General and Administrative. Since WebCDMS is exclusively used by Compliance, the costs were expended in Compliance.
- Office Costs are $91,000 under budget primarily due to lower-than-anticipated computer license, maintenance, and equipment expenditures.

Indirect Expenses

- Indirect Expenses are under budget by $657,000 due to the unfilled position in Standards. WECC's indirect allocation is based on actual FTEs in each Program Area.

Fixed Assets

- Computer and Software CapEx are under budget by $10,000 due to budgeted software modules for WECC's existing systems that were not purchased in 2014.
- Equipment CapEx are under budget by $31,000 due to budgeted multimedia equipment for remote training that was not purchased in 2014.

Reliability Assessment and Performance Analysis Program

Western Electricity Coordinating Council
201s Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Reliability Assessment and Performance Analysis

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ 3,767,309	$ 3,767,309	$ -	0.0%
Penalty Sanctions	785,698	785,698	-	0.0%
Total ERO Funding	**$ 4,553,007**	**$ 4,553,007**	**$ -**	0.0%
Membership Fees	-	-	-	
Grant Funding	3,638,249	3,628,308	9,941	0.3%
Services & Software			-	
Workshops	-	-	-	
Interest	25,859	18,484	7,375	39.9%
Miscellaneous	-	-	-	
Total Funding	**$ 8,217,115**	**$ 8,199,799**	**$ 17,316**	0.2%
Expenses				
Personnel Expenses				
Salaries	2,943,923	2,014,830	929,093	46.1%
Payroll Taxes	213,472	134,116	79,356	59.2%
Employee Benefits	312,572	296,187	16,385	5.5%
Savings & Retirement	283,761	134,116	149,645	111.6%
Total Personnel Expenses	**$ 3,753,728**	**$ 2,579,250**	**$ 1,174,478**	45.5%
Meeting Expenses				
Meetings	72,517	65,065	7,452	11.5%
Travel	158,447	148,800	9,647	6.5%
Conference Calls	28,106	30,750	(2,644)	-8.6%
Total Meeting Expenses	**$ 259,070**	**$ 244,615**	**$ 14,455**	5.9%
Operating Expenses				
Consultants & Contracts	2,107,336	3,368,000	(1,260,664)	-37.4%
Office Rent	540	-	540	
Office Costs	282,621	113,650	168,971	148.7%
Professional Services	3,249	-	3,249	
Miscellaneous	-	-	-	
Depreciation	318,058	211,000	107,058	50.7%
Total Operating Expenses	**$ 2,711,804**	**$ 3,692,650**	**$ (980,846)**	-26.6%
Total Direct Expenses	**$ 6,724,602**	**$ 6,516,515**	**$ 208,087**	3.2%
Indirect Expenses	2,994,486	2,554,048	440,438	17.2%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**9,719,088**	**9,070,563**	**648,525**	7.1%
Change in Assets	**$ (1,501,973)**	**$ (870,764)**	**$ (631,209)**	72.5%
Fixed Assets				
Depreciation	(318,058)	(211,000)	(107,058)	50.7%
Computer & Software CapEx	398,193	239,487	158,706	66.3%
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	(47,345)	(45,003)	(2,342)	5.2%
Incr(Dec) in Fixed Assets	**$ 32,790**	**$ (16,516)**	**$ 49,306**	-298.5%
Total Budget	**9,751,878**	**9,054,047**	**697,832**	7.7%
Change in Working Capital	**$ (1,534,763)**	**$ (854,248)**	**$ (680,515)**	79.7%
FTEs	25.9	23.6	2.3	
Headcount	28.0	23.0	5.0	

Significant Variance Explanations – Reliability Assessment and Performance Analysis

Personnel Expenses

- Salaries are $929,000 over budget due to a net increase of 4.4 FTEs (7 positions), budgeted labor float rate assumptions compared with actual vacancy rates, and incentives that were budgeted in General and Administrative. Additionally, nine positions were transferred to RAPA from Technical Committees and Member Forums, RAPA transferred one position to General and Administrative, General and Administrative transferred one executive position to RAPA to more closely align staff with work performed, and one position to Situation Awareness and Infrastructure Security. Positions were moved in 2014 to more appropriately align staff with work performed.
- Payroll Taxes are $79,000 over budget due to the net increase in FTEs and WECC's labor float assumptions.
- Savings and Retirement are $150,000 over budget due to an unbudgeted increase in the defined-contribution percentage, the net increase in FTEs and WECC's labor float assumptions.

Meeting Expenses

- Not applicable.

Operating Expenses

- Consultants and Contracts are $1.26 million under budget due to several factors:
  - RAS modeling contracts were under budget by $350,000 due to delays in vendor deliverables;
  - $169,000 was budgeted for data modeling software maintenance fees but was actually expensed as office costs;
  - RTEP consultants were under budget by $1.07 million due to usage of staff on some RTEP projects to minimize the cost of higher-priced consultants in order to maximize grant spending on other allowable costs and classification issues between consulting and license fees and fixed assets; and
  - Consulting dollars budgeted in Technical Committees and Forums were expensed in RAPA. The budget was $212,000 and actual expenditures on this project were $74,000.
  - Office Costs are $169,000 over budget primarily due to data modeling software maintenance fees that were originally budgeted in Consultants and Contracts but expensed as Office Costs.

Indirect Expenses

- Indirect Expenses are over budget by $440,000 due to the increase in FTEs in RAPA. WECC's indirect allocation is based on actual FTEs in each Program Area.

Fixed Assets

- Computer and Software CapEx are over budget by $159,000 primarily due to budget classification issues between consulting and fixed assets for the RTEP grant.

Training, Education, and Operator Certification Program

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Training and Education

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ 36,290	$ 36,290	$ -	0.0%
Penalty Sanctions	66,585	66,585	-	0.0%
Total ERO Funding	**$ 102,875**	**$ 102,875**	**$ -**	0.0%
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	386,380	519,804	(133,424)	-25.7%
Interest	848	1,566	(718)	-45.8%
Miscellaneous	-	-	-	
Total Funding	**$ 490,103**	**$ 624,245**	**$ (134,142)**	-21.5%
Expenses				
Personnel Expenses				
Salaries	83,916	146,942	(63,026)	-42.9%
Payroll Taxes	6,956	10,136	(3,180)	-31.4%
Employee Benefits	2,433	22,654	(20,221)	-89.3%
Savings & Retirement	8,358	10,136	(1,778)	-17.5%
Total Personnel Expenses	**$ 101,663**	**$ 189,868**	**$ (88,205)**	-46.5%
Meeting Expenses				
Meetings	49,477	56,040	(6,563)	-11.7%
Travel	5,597	7,836	(2,239)	-28.6%
Conference Calls	319	804	(485)	-60.3%
Total Meeting Expenses	**$ 55,393**	**$ 64,680**	**$ (9,287)**	-14.4%
Operating Expenses				
Consultants & Contracts	104,931	106,502	(1,571)	-1.5%
Office Rent	45,427	47,472	(2,045)	-4.3%
Office Costs	84,727	87,740	(3,013)	-3.4%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ 235,085**	**$ 241,714**	**$ (6,629)**	-2.7%
Total Direct Expenses	**$ 392,141**	**$ 496,262**	**$ (104,121)**	-21.0%
Indirect Expenses	98,237	196,829	(98,592)	-50.1%
Other Non-Operating Expenses	**$ 3,650**	**$ -**	**$ 3,650**	
Total Expenses	**494,028**	**693,091**	**(199,064)**	-28.7%
Change in Assets	**$ (3,924)**	**$ (68,846)**	**$ 64,922**	-94.3%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	(1,553)	(3,814)	2,261	-59.3%
Incr(Dec) in Fixed Assets	**$ (1,553)**	**$ (3,814)**	**$ 2,261**	-59.3%
Total Budget (Expenses plus Inc(Dec) in Fixed Assets	**492,475**	**689,277**	**(196,803)**	-28.6%
Change in Working Capital (Total Funding less Total Budget)	**$ (2,371)**	**$ (65,032)**	**$ 62,661**	-96.4%
FTEs	0.9	2.0	(1.2)	
Headcount	1.0	2.0	(1.0)	

Significant Variance Explanations – Training and Education

Funding

- Workshop Revenue is under budget by $133,000 due to lower-than-anticipated enrollment in WECC training classes.

Personnel Expenses

- Salaries are under budget by $63,000 due to 1.0 vacant position.
- Employee Benefits are $20,000 under budget due to 1.0 vacant position.

Meeting Expenses

- Not applicable.

Operating Expenses

- Not applicable.

Indirect Expenses

- Indirect Expenses are under budget by $99,000 due to 1.0 vacant position. WECC's indirect allocation is based on actual FTEs in each Program Area.

Fixed Assets

- Not applicable.

Situation Awareness and Infrastructure Security Program

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Situation Awareness and Infrastructure Security

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ 81,145	$ 81,145	$ -	0.0%
Penalty Sanctions	16,646	16,646	-	0.0%
Total ERO Funding	**$ 97,791**	**$ 97,791**	**$ -**	0.0%
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	-	-	-	
Interest	878	391	487	124.6%
Miscellaneous	-	-	-	
Total Funding	**$ 98,669**	**$ 98,182**	**$ 487**	0.5%
Expenses				
Personnel Expenses				
Salaries	130,656	47,976	82,680	172.3%
Payroll Taxes	9,568	3,228	6,340	196.4%
Employee Benefits	12,686	5,724	6,962	121.6%
Savings & Retirement	12,980	3,228	9,752	302.1%
Total Personnel Expenses	**$ 165,890**	**$ 60,156**	**$ 105,734**	175.8%
Meeting Expenses				
Meetings	-	-	-	
Travel	-	-	-	
Conference Calls	-	-	-	
Total Meeting Expenses	**$ -**	**$ -**	**$ -**	
Operating Expenses				
Consultants & Contracts	-	-	-	
Office Rent	-	-	-	
Office Costs	-	-	-	
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Direct Expenses	**$ 165,890**	**$ 60,156**	**$ 105,734**	175.8%
Indirect Expenses	91,587	49,207	42,380	86.1%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	**257,477**	**109,363**	**148,114**	135.4%
Change in Assets	**$ (158,807)**	**$ (11,181)**	**$ (147,626)**	1320.3%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	(1,608)	(953)	(655)	68.7%
Incr(Dec) in Fixed Assets	**$ (1,608)**	**$ (953)**	**$ (655)**	68.7%
Total Budget	**255,869**	**108,410**	**147,459**	136.0%
Change in Working Capital	**$ (157,199)**	**$ (10,228)**	**$ (146,971)**	1437.0%
FTEs	0.9	0.5	0.4	
Headcount	1.0	-	1.0	

Significant Variance Explanations – Situation Awareness and Infrastructure Security

Personnel Expenses

- Personnel Expenses are over budget by $106,000 due to the incremental 0.6 FTE allocation, which more accurately reflects actual time spent on Situation Awareness and Infrastructure Security activities.

Meeting Expenses

- Not applicable.

Operating Expenses

- Not applicable.

Indirect Expenses

- Indirect Expenses are over budget by $42,000 due to the increase in actual FTEs. WECC's indirect allocation is based on actual FTEs in each Program Area.

Fixed Assets

- Not applicable.

Technical Committees and Member Forums

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Technical Committees and Member Forums

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-		
Total Funding	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	70,917	874,612	(803,695)	-91.9%
Payroll Taxes	6,573	59,075	(52,502)	-88.9%
Employee Benefits	16,326	115,178	(98,852)	-85.8%
Savings & Retirement	6,698	59,075	(52,377)	-88.7%
Total Personnel Expenses	**$ 100,514**	**$ 1,107,940**	**$ (1,007,426)**	-90.9%
Meeting Expenses				
Meetings	76,619	278,090	(201,471)	-72.4%
Travel	82,762	128,720	(45,958)	-35.7%
Conference Calls	558	18,800	(18,242)	-97.0%
Total Meeting Expenses	**$ 159,939**	**$ 425,610**	**$ (265,671)**	-62.4%
Operating Expenses				
Consultants & Contracts	-	212,000	(212,000)	-100.0%
Office Rent	-	-	-	
Office Costs	7,728	35,203	(27,475)	-78.0%
Professional Services	825,863	465,756	360,107	77.3%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ 833,591**	**$ 712,959**	**$ 120,632**	16.9%
Total Direct Expenses	**$ 1,094,044**	**$ 2,246,509**	**$ (1,152,465)**	-51.3%
Indirect Expenses	(1,094,044)	(2,246,509)	1,152,465	-51.3%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	-	-	-	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Total Budget	-	-	-	
Change in Working Capital	**$ -**	**$ -**	**$ -**	
FTEs	0.7	9.0	(8.3)	
Headcount	-	9.0	(9.0)	

Significant Variance Explanations – Technical Committee and Member Forums

Personnel Expenses

- Salaries are under budget by $804,000 due to a shift of 9.0 positions from Technical Committees and Member Forums to RAPA to more appropriately align staffing with work performed.
- Payroll Taxes are under budget by $53,000 due to the shift of employees.
- Employee Benefits are under budget by $99,000 due to the shift of employees.
- Savings and Retirement are under budget by $52,000 due to the shift of employees.

Meeting Expenses

- Meetings are under budget by $201,500 due to an overall saving of $135,000 for Board meetings being held onsite and $66,300 for meetings budgeted for Technical Committees and Member Forums that has transitioned to RAPA.
- Travel is under budget by $46,000 due to $71,600 of travel budgeted for Technical Committees and Member Forums that has transitioned to RAPA as well as an overage of $25,600 of higher-than-anticipated travel for the Board of Directors.
- Conference Calls are $18,000 under budget due to lower-than-anticipated usage of $6,200 for the Board of Directors and $12,000 budgeted for Technical Committees and Member Forums transitioned to RAPA.

Operating Expenses

- Contracts and Consultant are $212,000 under budget due to a contract for data validation and voltage stability shifting from Technical Committees and Member Forums to RAPA. The actual contractual cost of $74,000 was expensed in RAPA.
- Office Costs are $27,000 under budget due to the transfer of Technical Committees and Member Forums' FTEs to RAPA.
- Professional Services are $360,000 over budget due to an increase in the number of compensable Board Meetings and restructured Board member compensation.

Indirect Expenses

- Indirect Expenses are under budget by $1.15 million due to the shift of FTEs to RAPA. WECC's indirect allocation is based on actual FTEs in each Program Area.

Fixed Assets

- Not applicable.

General and Administrative

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
General and Administrative

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	1,959,848	1,801,127	158,721	8.8%
Payroll Taxes	101,176	92,319	8,857	9.6%
Employee Benefits	181,942	188,224	(6,282)	-3.3%
Savings & Retirement	130,917	92,319	38,598	41.8%
Total Personnel Expenses	**$ 2,373,883**	**$ 2,173,989**	**$ 199,894**	9.2%
Meeting Expenses				
Meetings	9,166	11,250	(2,084)	-18.5%
Travel	148,305	121,750	26,555	21.8%
Conference Calls	9,636	8,100	1,536	19.0%
Total Meeting Expenses	**$ 167,107**	**$ 141,100**	**$ 26,007**	18.4%
Operating Expenses				
Consultants & Contracts	134,550	90,000	44,550	49.5%
Office Rent	900,861	888,600	12,261	1.4%
Office Costs	119,735	196,881	(77,146)	-39.2%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	202,995	205,000	(2,005)	-1.0%
Total Operating Expenses	**$ 1,358,141**	**$ 1,380,481**	**$ (22,340)**	-1.6%
Total Direct Expenses	**$ 3,899,131**	**$ 3,695,570**	**$ 203,561**	5.5%
Indirect Expenses	(3,899,131)	(3,695,570)	(203,561)	5.5%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	-	-	-	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	(202,995)	(205,000)	2,005	-1.0%
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	7,647	-	7,647	
Allocation of Fixed Assets	195,348	205,000	(9,652)	-4.7%
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Total Budget	-	-	-	
Change in Working Capital	**$ -**	**$ -**	**$ -**	
FTEs	17.5	15.2	2.3	
Headcount	17.0	16.0	1.0	

Significant Variance Explanations – General and Administrative

Personnel Expenses

- Salaries are over by a net of $159,000 due to a net increase of 2.3 FTEs, labor float assumptions compared to actual vacancy rates, unbudgeted recruiting fees, and an underrun in incentives that were expensed in other departments.
- Savings and Retirement are $39,000 over budget due to an unanticipated increase in the defined-contribution percentage, the increase in FTEs and WECC's labor float assumptions.

Meeting Expenses

- Travel is over budget by $27,000 primarily due to an increased engagement and outreach to stakeholders by WECC's new Chief Executive Officer.

Operating Expenses

- Consultants and Contracts are $45,000 over budget primarily due to unbudgeted costs related to the Regional Executive Management Group.
- Office costs are $77,000 under budget primarily due to a consolidation of equipment rentals and decreased office supply usage post-bifurcation.

Indirect Expenses

- Indirect Expenses are over budget by $204,000 due to the increase in actual FTEs. WECC's indirect allocation is based on actual FTEs in each Program Area.

Fixed Assets

- Not applicable.

Legal

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Legal

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	967,809	657,788	310,021	47.1%
Payroll Taxes	56,480	44,388	12,092	27.2%
Employee Benefits	86,877	77,152	9,725	12.6%
Savings & Retirement	72,640	44,388	28,252	63.6%
Total Personnel Expenses	**$ 1,183,806**	**$ 823,716**	**$ 360,090**	43.7%
Meeting Expenses				
Meetings	-	-	-	
Travel	16,355	48,000	(31,645)	-65.9%
Conference Calls	2,087	1,200	887	73.9%
Total Meeting Expenses	**$ 18,442**	**$ 49,200**	**$ (30,758)**	-62.5%
Operating Expenses				
Consultants & Contracts	675	-	675	
Office Rent	-	-	-	
Office Costs	28,102	28,690	(588)	-2.0%
Professional Services	424,238	190,000	234,238	123.3%
Miscellaneous	-	-	-	
Depreciation	8,489	8,000	489	6.1%
Total Operating Expenses	**$ 461,504**	**$ 226,690**	**$ 234,814**	103.6%
Total Direct Expenses	**$ 1,663,752**	**$ 1,099,606**	**$ 564,146**	51.3%
Indirect Expenses	(1,663,752)	(1,099,606)	(564,146)	51.3%
Other Non-Operating Expenses	**$ 3,090**	**$ -**	**$ 3,090**	
Total Expenses	**3,090**	**-**	**3,090**	
Change in Assets	**$ (3,090)**	**$ -**	**$ (3,090)**	
Fixed Assets				
Depreciation	(8,489)	(8,000)	(489)	6.1%
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	8,489	8,000	489	6.1%
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Total Budget	**3,090**	**-**	**3,090**	
Change in Working Capital	**$ (3,090)**	**$ -**	**$ (3,090)**	
FTEs	6.0	6.0	-	
Headcount	6.0	6.0	-	

Significant Variance Explanations – Legal

Personnel Expenses

- Salaries are over budget by $310,000 due to WECC's budgeted labor float rate assumptions compared with actual vacancy rates and incentives that were budgeted in Human Resources and General and Administrative.
- Payroll Taxes are $12,000 over budget due to WECC's labor float assumptions and other increases in Salaries.
- Employee Benefits are $10,000 under budget due to lower-than-anticipated plan enrollment among existing employees and under-utilization of training.
- Savings and Retirement are $28,000 over budget due to an unanticipated increase in the defined-contribution percentage, WECC's labor float assumptions, and other increases in Salaries.

Meeting Expenses

- Travel is $32,000 under budget due to cost-saving efforts and lower-than-anticipated travel requirements.

Operating Expenses

- Professional Services are $234,000 over budget due to an increase in legal fees related to unanticipated litigation.

Indirect Expenses

- Indirect Expenses are over budget by $564,000 due to the increase in actual expenditures.

Fixed Assets

- Not applicable.

Information Technology

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Information Technology

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	633,746	670,107	(36,361)	-5.4%
Payroll Taxes	48,920	45,103	3,817	8.5%
Employee Benefits	97,999	101,928	(3,929)	-3.9%
Savings & Retirement	54,278	45,103	9,175	20.3%
Total Personnel Expenses	**$ 834,943**	**$ 862,241**	**$ (27,298)**	-3.2%
Meeting Expenses				
Meetings	-	-	-	
Travel	2,995	13,200	(10,205)	-77.3%
Conference Calls	6,223	7,200	(977)	-13.6%
Total Meeting Expenses	**$ 9,218**	**$ 20,400**	**$ (11,182)**	-54.8%
Operating Expenses				
Consultants & Contracts	42,639	36,000	6,639	18.4%
Office Rent	260	-	260	
Office Costs	354,317	340,800	13,517	4.0%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	83,838	106,000	(22,162)	-20.9%
Total Operating Expenses	**$ 481,054**	**$ 482,800**	**$ (1,746)**	-0.4%
Total Direct Expenses	**$ 1,325,215**	**$ 1,365,441**	**$ (40,226)**	-2.9%
Indirect Expenses	(1,325,215)	(1,365,441)	40,226	-2.9%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses	-	-	-	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	(83,838)	(106,000)	22,162	-20.9%
Computer & Software CapEx	101,702	60,000	41,702	69.5%
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	48,359	105,000	(56,641)	-53.9%
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	(66,223)	(59,000)	(7,223)	12.2%
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ 0**	
Total Budget	**-**	**-**	**0**	
Change in Working Capital	**$ -**	**$ -**	**$ (0)**	
FTEs	7.2	9.0	(1.8)	
Headcount	8.0	9.0	(1.0)	

Significant Variance Explanations – Information Technology

Personnel Expenses

- Not applicable.

Meeting Expenses

- Travel is $10,000 under budget due to lower-than-anticipated travel requirements as well as cost-saving efforts.

Operating Expenses

- Not applicable.

Indirect Expenses

- Not applicable.

Fixed Assets

- Computer and Software CapEx are $42,000 over budget due to higher-than-anticipated costs for WECC's new website.
- Equipment CapEx is $57,000 under budget due to lower-than-anticipated equipment needs to support WECC's new website.

Human Resources

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Human Resources

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software			-	
Workshops	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-		
Total Funding	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	257,936	384,508	(126,572)	-32.9%
Payroll Taxes	20,600	14,190	6,410	45.2%
Employee Benefits	431,923	414,876	17,047	4.1%
Savings & Retirement	39,357	14,190	25,167	177.4%
Total Personnel Expenses	**$ 749,816**	**$ 827,764**	**$ (77,948)**	-9.4%
Meeting Expenses				
Meetings	3	-	3	
Travel	10,429	10,200	229	2.2%
Conference Calls	667	1,000	(333)	-33.3%
Total Meeting Expenses	**$ 11,099**	**$ 11,200**	**$ (101)**	-0.9%
Operating Expenses				
Consultants & Contracts	33,484	150,000	(116,516)	-77.7%
Office Rent	-	-	-	
Office Costs	97,165	59,100	38,065	64.4%
Professional Services	13,093	17,000	(3,907)	-23.0%
Miscellaneous	-	-	-	
Depreciation	692	7,000	(6,308)	-90.1%
Total Operating Expenses	**$ 144,434**	**$ 233,100**	**$ (88,666)**	-38.0%
Total Direct Expenses	**$ 905,349**	**$ 1,072,064**	**$ (166,715)**	-15.6%
Indirect Expenses	(905,349)	(1,072,064)	166,715	-15.6%
Other Non-Operating Expenses	**$ 852**	**$ -**	**$ 852**	
Total Expenses	**852**	**-**	**852**	
Change in Assets	**$ (852)**	**$ -**	**$ (852)**	
Fixed Assets				
Depreciation	(692)	(7,000)	6,308	-90.1%
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	692	7,000	(6,308)	-90.1%
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Total Budget	**852**	**-**	**852**	
Change in Working Capital	**$ (852)**	**$ -**	**$ (852)**	
FTEs	2.9	3.0	(0.1)	
Headcount	3.0	3.0	-	

Significant Variance Explanations – Human Resources

Personnel Expenses

- Salaries are under budget by $127,000 due to incentives budgeted in Human Resources but expensed in other departments.
- Savings and Retirement are $25,000 over budget due to an unanticipated increase in the defined-contribution percentage and WECC's labor float assumptions.

Meeting Expenses

- Not applicable.

Operating Expenses

- Consultants and Contracts are $117,000 under budget due to lower-than-anticipated costs of compensation surveys and consulting fees.
- Office Costs are $38,000 over budget due to an increase in recruiting costs as well as unbudgeted expenditures for compensation survey data.

Indirect Expenses

- Indirect Expenses are under budget by $167,000 due to the decrease in actual expenditures in Human Resources.

Fixed Assets

- Not applicable.

Finance and Accounting

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Finance and Accounting

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Membership Fees	-	-	-	
Grant Funding	-	-	-	
Services & Software	-	-	-	
Workshops	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-		
Total Funding	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	352,707	280,800	71,907	25.6%
Payroll Taxes	23,325	18,992	4,333	22.8%
Employee Benefits	38,916	63,758	(24,842)	-39.0%
Savings & Retirement	36,580	18,992	17,588	92.6%
Total Personnel Expenses	**$ 451,528**	**$ 382,542**	**$ 68,986**	18.0%
Meeting Expenses				
Meetings	840	-	840	
Travel	3,237	11,250	(8,013)	-71.2%
Conference Calls	392	400	(8)	-2.0%
Total Meeting Expenses	**$ 4,469**	**$ 11,650**	**$ (7,181)**	-61.6%
Operating Expenses				
Consultants & Contracts	-	-	-	
Office Rent	-	-	-	
Office Costs	111,635	84,600	27,035	32.0%
Professional Services	96,299	86,000	10,299	12.0%
Miscellaneous	-	-	-	
Depreciation	6,526	7,000	(474)	-6.8%
Total Operating Expenses	**$ 214,460**	**$ 177,600**	**$ 36,860**	20.8%
Total Direct Expenses	**$ 670,457**	**$ 571,792**	**$ 98,665**	17.3%
Indirect Expenses	(671,753)	(571,792)	(99,961)	17.5%
Other Non-Operating Expenses	**$ 1,296**	**$ -**	**$ 1,296**	
Total Expenses	-	-	-	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	(6,526)	(7,000)	474	-6.8%
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	6,526	7,000	(474)	-6.8%
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Total Budget	-	-	-	
Change in Working Capital	**$ -**	**$ -**	**$ -**	
FTEs	4.2	4.7	(0.5)	
Headcount	5.0	5.0	-	

Significant Variance Explanations – Finance and Accounting

Personnel Expenses

- Salaries are over budget by $72,000 due to WECC's budgeted labor float assumptions compared with actual vacancy rates and incentives that were budgeted in Human Resources.
- Employee Benefits are $25,000 under budget due to lower-than-anticipated plan enrollment among existing employees as well as under-utilized employee training.
- Savings and Retirement are $18,000 over budget due to an unanticipated increase in the defined-contribution percentage, WECC's labor float assumptions, and other increases in Salaries.

Meeting Expenses

- Not applicable.

Operating Expenses

- Office Costs are over budget by $27,000 due an unanticipated tax payment to the State of Washington for Business and Occupancy taxes.
- Professional Services are over budget by $10,000 due to higher-than-anticipated audit fees.

Indirect Expenses

- Indirect Expenses are over budget by $100,000 due to the increase in actual costs in Finance and Accounting.

Fixed Assets

- Not applicable.

Section B
Non-Statutory Programs

2014 Business Plan and Budget

Western Renewable Energy Generation Information System (WREGIS)

Western Electricity Coordinating Council
2014 Statement of Activities, Fixed Asset Expenditures, and Change in Working Capital
Non-Statutory Summary

	2014 Actual	2014 Budget	2014 Variance Over(Under)	%
Funding				
WECC Funding				
WECC Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Total ERO Funding	**$ -**	**$ -**	**$ -**	
Membership Fees	3,022,447	1,896,000	1,126,447	59.4%
Grant Funding	-	-	-	
Services & Software			-	
Workshops	1,710	7,800	(6,090)	-78.1%
Interest	29,325	-	29,325	
Miscellaneous	-	-	-	
Total Funding	**$ 3,053,482**	**$ 1,903,800**	**$ 1,149,682**	60.4%
Expenses				
Personnel Expenses				
Salaries	280,854	350,730	(69,876)	-19.9%
Payroll Taxes	22,300	23,715	(1,415)	-6.0%
Employee Benefits	30,046	65,935	(35,889)	-54.4%
Savings & Retirement	24,596	23,715	881	3.7%
Total Personnel Expenses	**$ 357,796**	**$ 464,094**	**$ (106,298)**	-22.9%
Meeting Expenses				
Meetings	1,438	13,225	(11,787)	-89.1%
Travel	6,418	61,000	(54,582)	-89.5%
Conference Calls	886	-	886	
Total Meeting Expenses	**$ 8,742**	**$ 74,225**	**$ (65,483)**	-88.2%
Operating Expenses				
Consultants & Contracts	1,595	6,000	(4,405)	-73.4%
Office Rent	66	-	66	
Office Costs	451,607	557,050	(105,443)	-18.9%
Professional Services	-	16,500	(16,500)	-100.0%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ 453,268**	**$ 579,550**	**$ (126,282)**	-21.8%
Total Direct Expenses	**$ 819,806**	**$ 1,117,869**	**$ (298,063)**	-26.7%
Indirect Expenses	409,077	541,111	(132,034)	-24.4%
Other Non-Operating Expenses	**$ 19,000**	**$ -**	**$ 19,000**	
Total Expenses	1,247,883	1,658,980	(411,097)	-24.8%
Change in Assets	**$ 1,805,599**	**$ 244,820**	**$ 1,560,779**	637.5%
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx				
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	-	-	-	
Incr(Dec) in Fixed Assets	**$ -**	**$ -**	**$ -**	
Total Budget	**1,247,883**	**1,658,980**	**(411,097)**	-24.8%
Change in Working Capital	**$ 1,805,599**	**$ 244,820**	**$ 1,560,779**	637.5%
FTEs	4.00	5.0	(1.0)	
Headcount	4.00	5.0	(1.0)	

Significant Variance Explanations – Non-Statutory

Funding

- Membership Fees are $1.13 million over budget due to higher-than-anticipated participation in WREGIS.
- Interest Income is $29,000 over budget due to higher-than-anticipated rates of return on non-statutory cash balances.

Personnel Expenses

- Salaries are $70,000 under budget due to 1.0 vacant position.
- Employee Benefits are $36,000 under budget due to lower-than-anticipated plan enrollment with existing employees as well as employee training needs that were less than expected.

Meeting Expenses

- Meetings are $12,000 under budget due to lower-than-anticipated costs for WREGIS meetings being held onsite and via webinar.
- Travel is $55,000 under budget due to WREGIS offsite travel being lower than anticipated.

Operating Expenses

- Operating Expenses decrease by $126,000 primarily due to decreases in WREGIS software licensing fees and lower-than-budgeted legal fees.

Indirect Expenses

- Indirect Expenses are under budget by $132,000 due to the indirect allocation being based on actual FTEs.

Other Non-Operating Expenses

- Other Non-Operating Expenses are over budget by $19,000 due to unbudgeted adjustments to the allowance for doubtful accounts.

ATTACHMENT 10

2014 ACTUAL COST-TO-BUDGET COMPARISON

AND

2014 AUDITED FINANCIAL REPORT

FOR

PEAK RELIABILITY, INC.

Peak Reliability

2014 – Actual to Budget Variance Analysis

May 27, 2015

Vancouver, Washington
Loveland, Colorado
www.peakrc.com

PEAKRELIABILITY
assuring the wide area view

Peak Reliability

2014—Actual to Budget Variance Analysis

For the year ending December 31, 2014, Peak Reliability (Peak) was substantially on budget with an under budget variance of $433.5k (1.3 percent) for total expenses and fixed asset purchases. Significant variances within expense categories include, higher personnel expenses driven by lower than planned vacancy rates which were offset by lower levels of fixed asset additions due to timing of projects, including the Enhanced Curtailment Calculator (ECC) and lower computer and maintenance costs. Higher than budgeted director compensation was offset by savings initiatives aimed at reducing meeting and travel expenses.

2014 ACTUAL VERSUS BUDGET BY CATEGORY

STATUTORY

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Total Funding	**$ 30,945,496**	**$ 29,724,031**	**$ 1,221,465**	4.1%
Expenses				
Personnel Expenses	21,342,606	19,397,409	1,945,197	10.0%
Meeting Expenses	624,742	1,155,405	(530,663)	-45.9%
Consultants & Contracts	1,411,968	1,267,500	144,468	11.4%
Office Rent	1,400,067	1,276,728	123,339	9.7%
Office Costs	5,813,051	6,986,326	(1,173,275)	-16.8%
Professional Services	903,079	663,280	239,799	36.2%
Other Non-Operating Expenses	56	-	56	
Fixed Asset Increase	1,029,593	2,212,000	(1,182,407)	-53.5%
TOTAL BUDGET	$ 32,525,163	$ 32,958,648	(433,485)	-1.3%
TOTAL CHANGE IN WORKING CAPITAL	**$ (1,579,667)**	**$ (3,234,617)**	**$ 1,654,950**	-51.2%
FTEs	137.1	149.1	(12.0)	-8.0%
HC	141.0	155.0	(14.0)	-9.0%

Following is a discussion of the major factors influencing actual to budget performance in 2014:

- **Funding** – Peak was over budget primarily due to amounts paid by BC Hydro under a contract to have Peak continue to provide Reliability Coordinator functions. The amounts recognized and collected in 2014 have been used to offset 2015 assessments billed to other Load Serving Entities and will result in Peak being under

budget in 2015 by a similar amount. Peak also received unbudgeted federal grant funds in 2014.

- **Employee Vacancies** - The company ended the year 12.0 FTEs under budget, with a vacancy rate of 8.0 percent for 2014.
- **Personnel Expenses** were $1.95M, or 10.0 percent over budget, primarily due to lower levels of employee vacancy than the 15.0 percent budgeted.
- **Meetings, Travel, Conferencing and Webinar** expenses were under budget $530.7k, or 45.9 percent, primarily due to lower than anticipated travel and meeting costs.
- **Consultants and Contracts** expenses were $144.5k, or 11.4 percent over budget due primarily to consulting costs associated with the development of Peak's Performance Metrics program.
- **Rent** expense was $123.3k, or 9.7 percent, over budget due primarily to additional space leased in Loveland, Co, which was previously unbudgeted.
- **Office Costs, Professional Services and Miscellaneous**
  - Office Costs were $1.17M, or 16.8 percent, under budget primarily due to lower than budgeted computer supplies and maintenance costs driven by maintenance renewals at lower than budgeted rates.
  - Professional Services were $240.0k, or 36.2 percent, over budget due primarily to higher director compensation driven by a director compensation agreement approved after budget development.
- **Depreciation** was $497.9k, or 13.7 percent, over budget due primarily to higher levels of assets in service during the year than budgeted.
- **Fixed Asset Purchases**, excluding a credit for depreciation, were $1.182M, or 53.5 percent, under budget primarily due to delay in spending on large projects, including ECC.
- **Allocation of Indirect Expenses and Fixed Assets by Program** – Total direct expenses of the administrative programs were $7.7M, which was $92.5k, or 1.2 percent under budget. Direct expenses were under budget primarily due to lower personnel expenses as a result of vacancies greater than budgeted. The actual and budgeted allocations of indirect expenses by FTE were $66.6k and $65.7k, respectively, for an increase per FTE of $0.9k. Total fixed assets, net of depreciation for the administrative programs were ($80.0k), which was $109.0k, or 375.8%, under budget.

Use of Statutory Funds for Non-Statutory Activities

Peak did not use statutory funds for non-statutory activities as Peak's non-statutory activities operate only when they cover the costs associated with the activity.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
STATUTORY

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Funding				
Assessments	$ 30,604,721	$ 29,568,031	$ 1,036,690	
Federal Grants	323,063	-	323,063	
Interest	30,836	156,000	(125,164)	
Miscellaneous	(13,124)	-	(13,124)	
Total Funding (A)	**$ 30,945,496**	**$ 29,724,031**	**$ 1,221,465**	4.1%
Expenses				
Personnel Expenses				
Salaries	$ 16,832,156	$ 14,959,388	$ 1,872,768	
Payroll Taxes	1,142,807	963,709	179,098	
Benefits	2,025,611	2,510,603	(484,992)	
Retirement Costs	1,342,032	963,709	378,323	
Total Personnel Expenses	**$ 21,342,606**	**$ 19,397,409**	**$ 1,945,197**	10.0%
Meeting Expenses				
Meetings	$ 120,611	$ 306,183	$ (185,572)	
Travel	496,811	804,138	(307,327)	
Conference Calls	7,320	45,084	(37,764)	
Total Meeting Expenses	**$ 624,742**	**$ 1,155,405**	**$ (530,663)**	-45.9%
Operating Expenses				
Consultants & Contracts	$ 1,411,968	$ 1,267,500	$ 144,468	
Office Rent	1,400,067	1,276,728	123,339	
Office Costs	5,813,051	6,986,326	(1,173,275)	
Professional Services	903,079	663,280	239,799	
Miscellaneous	-	-	-	
Depreciation	4,122,887	3,625,000	497,887	
Total Operating Expenses	**$ 13,651,053**	**$ 13,818,834**	**$ (167,781)**	-1.2%
Total Direct Expenses	**$ 35,618,401**	**$ 34,371,648**	**$ 1,246,753**	3.6%
Indirect Expenses	**$ -**	**$ -**	**$ -**	
Other Non-Operating Expenses	**$ 56**	**$ -**	**$ 56**	
Total Expenses (B)	**$ 35,618,458**	**$ 34,371,648**	**$ 1,246,810**	3.6%
Change in Assets	**$ (4,672,962)**	**$ (4,647,617)**	**$ (25,345)**	0.5%
Fixed Assets				
Depreciation	$ (4,122,887)	$ (3,625,000)	(497,887)	
Computer & Software CapEx	249,007	1,373,000	(1,123,993)	
Furniture & Fixtures CapEx	0	36,000	(36,000)	
Equipment CapEx	711,472	803,000	(91,528)	
Leasehold Improvements	69,114	-	69,114	
Allocation of Fixed Assets	$ -	$ -	$ -	
Incr(Dec) in Fixed Assets (C)	**$ (3,093,295)**	**$ (1,413,000)**	**$ (1,680,295)**	118.9%
TOTAL BUDGET (B+C)	**32,525,163**	**32,958,648**	**(433,485)**	-1.3%
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ (1,579,667)**	**$ (3,234,617)**	**$ 1,654,950**	-51.2%
FTEs	137.1	149.1	(12.0)	-8.0%

Statutory Working Capital Reserve Analysis

Working Capital Reserve Analysis 2014			
STATUTORY			
	Actual	Budget	Variance Over(Under)
Beginning Working Capital Reserve, December 31, 2013	$ -	$ -	$ -
Plus: Transfer of Reserves from WECC, January 2, 2014	5,811,568	5,811,568	0
Plus: 2014 Funding (from Load Serving Entities (LSE) or designees)	30,604,721	29,568,031	1,036,690
Plus: 2014 Other funding sources	340,775	156,000	184,775
Less: 2014 expenses & capital expenditures	(32,525,163)	(32,958,648)	433,485
Working Capital Reserve, December 31, 2014	**$ 4,231,901**	**$ 2,576,951**	**$ 1,654,950**

Peak ended 2014 with working capital reserves of $4.2 million, $1.65 million greater than expected primarily due to $1.04 million of greater funding than planned. The increased funding will offset funding budgeted in 2015.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Funding				
Assessments	$ 30,604,721	$ 29,568,031	$ 1,036,690	3.5%
Federal Grants	323,063	-	323,063	
Interest	30,836	156,000	(125,164)	-80.2%
Miscellaneous	(13,124)	-	(13,124)	
Total Funding (A)	**$ 30,945,496**	**$ 29,724,031**	**$ 1,221,465**	4.1%
Expenses				
Personnel Expenses				
Salaries	$ 13,847,146	$ 11,932,371	$ 1,914,775	16.0%
Payroll Taxes	977,670	787,893	189,777	24.1%
Benefits	1,329,318	1,680,551	(351,233)	-20.9%
Retirement Costs	1,150,168	787,893	362,275	46.0%
Total Personnel Expenses	**$ 17,304,301**	**$ 15,188,708**	**$ 2,115,593**	13.9%
Meeting Expenses				
Meetings	$ 23,001	$ 1,083	$ 21,918	2023.8%
Travel	314,845	455,288	(140,443)	-30.8%
Conference Calls	6,125	15,384	(9,259)	-60.2%
Total Meeting Expenses	**$ 343,971**	**$ 471,755**	**$ (127,784)**	-27.1%
Operating Expenses				
Consultants & Contracts	$ 879,317	$ 950,000	$ (70,683)	-7.4%
Office Rent	120,055	27,996	92,059	328.8%
Office Costs	5,230,803	6,291,501	(1,060,698)	-16.9%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	4,008,767	3,618,000	390,767	10.8%
Total Operating Expenses	**$ 10,238,943**	**$ 10,887,497**	**$ (648,554)**	-6.0%
Total Direct Expenses	**$ 27,887,215**	**$ 26,547,960**	**$ 1,339,255**	5.0%
Indirect Expenses	**$ 7,731,243**	**$ 7,823,688**	**$ (92,445)**	-1.2%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ 35,618,458**	**$ 34,371,648**	**$ 1,246,810**	3.6%
Change in Assets	**$ (4,672,962)**	**$ (4,647,617)**	**$ (25,345)**	0.5%
Fixed Assets				
Depreciation	(4,008,767)	(3,618,000)	(390,767)	10.8%
Computer & Software CapEx	249,007	1,373,000	(1,123,993)	-81.9%
Furniture & Fixtures CapEx	0	-	0	
Equipment CapEx	686,047	803,000	(116,953)	-14.6%
Leasehold Improvements	60,389	-	60,389	
Allocation of Fixed Assets	$ (79,970)	$ 29,000	$ (108,970)	-375.8%
Incr(Dec) in Fixed Assets (C)	**$ (3,093,295)**	**$ (1,413,000)**	**$ (1,680,295)**	118.9%
TOTAL BUDGET (B+C)	**32,525,163**	**32,958,648**	**(433,485)**	-1.3%
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ (1,579,667)**	**$ (3,234,617)**	**$ 1,654,950**	-51.2%
FTEs	116.1	119.1	(3.0)	

Assessments are higher than budget due to amounts paid by BC Hydro under a contract which included agreement to pay a portion of amounts originally assessed for 2014.

Unbudgeted **Federal Grant** revenue was generated with Peak's finalization of the Western Interconnection Synchrophasor Program (WISP) grant from the Department of Energy (DOE). Amounts recorded under the not yet finalized DOE Peak Reliability Synchrophasor Program (PRSP) grant also generated unbudgeted revenue.

Interest Income is under budget due to lower cash balances driven by delayed assessment collections.

Miscellaneous income is under budget due to recognition of a loss on asset retirements.

Personnel Expense

- Salaries were higher due to lower vacancy rates than budgeted and unbudgeted higher rates of pay under a new union contract.
- Payroll taxes were higher due to higher salaries.
- Benefits were lower due to lower than budgeted enrollment in and usage of benefit plans by employees.
- Retirement costs are over budget due to higher salaries and a higher defined contribution rate than budgeted.

Meeting Expense

- Meeting costs were budgeted within the General and Administrative group but recorded in the Situational Awareness program.
- Travel costs are lower than budget due to cost savings.

Operating Expenses

- Consultants and contracts are lower than budget due to cost savings.
- Office rent is higher than budget due to higher levels of office maintenance and security activities.
- Office costs are lower than budget primarily due to lower computer maintenance and licensing costs driven by renewals at lower than budgeted rates.
- Depreciation is higher than budget due to higher levels of fixed assets in service during the year than expected.

Fixed Asset Purchases

- Computer and software equipment purchases are lower than budget primarily due to timing of software purchases and implementation.
- Equipment purchases are lower than budget due to assets budgeted as equipment purchases but placed in service as leasehold improvements.
- Leasehold improvements were budgeted in equipment purchases.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
TECHNICAL COMMITTEES AND MEMBER FORUMS

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Funding				
Assessments	$ -	$ -	$ -	
Federal Grants	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	$ -	$ -	$ -	
Payroll Taxes	-	-	-	
Benefits	5,103	-	5,103	
Retirement Costs	-	-	-	
Total Personnel Expenses	**$ 5,103**	**$ -**	**$ 5,103**	
Meeting Expenses				
Meetings	$ 94,315	$ 260,000	$ (165,685)	-63.7%
Travel	58,751	42,000	16,751	39.9%
Conference Calls	-	2,680	(2,680)	-100.0%
Total Meeting Expenses	**$ 153,066**	**$ 304,680**	**$ (151,614)**	-49.8%
Operating Expenses				
Consultants & Contracts	$ 2,149	$ -	$ 2,149	
Office Rent	-	-	-	
Office Costs	5,375	2,350	3,025	128.7%
Professional Services	624,480	362,280	262,200	72.4%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ 632,005**	**$ 364,630**	**$ 267,375**	73.3%
Total Direct Expenses	**$ 790,173**	**$ 669,310**	**$ 120,863**	18.1%
Indirect Expenses	**$ (790,173)**	**$ (669,310)**	**$ (120,863)**	18.1%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ -**	**$ -**	**$ -**	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	$ -	$ -	$ -	
Incr(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B+C)	**-**	**-**	**-**	
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ -**	**$ -**	**$ -**	
FTEs	-	-	-	

Meeting Expense

- Meeting costs were lower than budget due to cost savings.
- Travel costs were higher due to more meetings taking place than were budgeted.

Operating Expenses

- Professional services were higher than budget due to director compensation under an agreement that was higher than was budgeted.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
GENERAL AND ADMINISTRATIVE

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Funding				
Assessments	$ -	$ -	$ -	
Federal Grants	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	$ 1,614,049	$ 1,366,486	$ 247,563	18.1%
Payroll Taxes	70,323	74,191	(3,868)	-5.2%
Benefits	94,014	145,572	(51,558)	-35.4%
Retirement Costs	87,437	74,191	13,246	17.9%
Total Personnel Expenses	**$ 1,865,822**	**$ 1,660,440**	**$ 205,382**	12.4%
Meeting Expenses				
Meetings	$ 425	$ 45,100	$ (44,675)	-99.1%
Travel	63,252	237,250	(173,998)	-73.3%
Conference Calls	1,066	19,620	(18,554)	-94.6%
Total Meeting Expenses	**$ 64,742**	**$ 301,970**	**$ (237,228)**	-78.6%
Operating Expenses				
Consultants & Contracts	$ 431,441	$ 197,500	$ 233,941	118.5%
Office Rent	1,279,975	1,248,732	31,243	2.5%
Office Costs	353,768	246,111	107,657	43.7%
Professional Services	14	-	14	
Miscellaneous	-	-	-	
Depreciation	83,485	7,000	76,485	1092.6%
Total Operating Expenses	**$ 2,148,683**	**$ 1,699,343**	**$ 449,340**	26.4%
Total Direct Expenses	**$ 4,079,247**	**$ 3,661,753**	**$ 417,494**	11.4%
Indirect Expenses	**$ (4,079,247)**	**$ (3,661,753)**	**$ (417,494)**	11.4%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ -**	**$ -**	**$ -**	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	(83,485)	(7,000)	(76,485)	1092.6%
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	36,000	(36,000)	-100.0%
Equipment CapEx	25,425	-	25,425	
Leasehold Improvements	8,725	-	8,725	
Allocation of Fixed Assets	$ 49,335	$ (29,000)	$ 78,335	-270.1%
Incr(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B+C)	**-**	**-**	**-**	
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ -**	**$ -**	**$ -**	
FTEs	9.0	12.0	(3.0)	-25.0%

Personnel Expense

- Salaries were higher due to higher rates of pay for filled positions, offset slightly by vacant positions.
- Benefits were lower due to vacancies and lower than budgeted enrollment in and usage of benefit plans by employees.
- Retirement costs are over budget primarily due to a higher defined contribution rate than budgeted.

Meeting Expense

- Meeting costs were lower due to lower than plan costs.
- Travel costs were lower primarily due to decreased travel of key employees and cost savings.
- Conference call costs were lower due to cost savings driven by a new service provider.

Operating Expenses

- Consultants and contracts were higher than budget due to management consultants cost associated with the development of Peak's Performance Metrics program.
- Office rent was higher than budget due to additional space leased in Loveland, CO which was unbudgeted, offset by property taxes of leased facilities charged to office costs category.
- Office costs were higher due to leased facilities property taxes which were budgeted in office rent.
- Depreciation was budgeted within the SAIS program but recorded in General and Administrative.

Fixed Asset Purchases

- Furniture and fixtures are lower than budget due to assets budget as furniture and fixtures, but placed in service as equipment.
- Equipment purchases were budgeted as furniture and fixtures purchases.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
LEGAL AND REGULATORY

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Funding				
Assessments	$ -	$ -	$ -	
Federal Grants	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	$ 234,385	$ 753,162	$ (518,777)	-68.9%
Payroll Taxes	17,170	51,174	(34,004)	-66.4%
Benefits	24,761	87,069	(62,308)	-71.6%
Retirement Costs	20,433	51,174	(30,741)	-60.1%
Total Personnel Expenses	**$ 296,750**	**$ 942,579**	**$ (645,829)**	-68.5%
Meeting Expenses				
Meetings	$ -	$ -	$ -	
Travel	5,963	36,000	(30,037)	-83.4%
Conference Calls	11	1,200	(1,189)	-99.1%
Total Meeting Expenses	**$ 5,975**	**$ 37,200**	**$ (31,225)**	-83.9%
Operating Expenses				
Consultants & Contracts	$ 17,341	$ 120,000	$ (102,659)	-85.5%
Office Rent	-	-	-	
Office Costs	6,851	28,864	(22,013)	-76.3%
Professional Services	245,227	190,000	55,227	29.1%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ 269,418**	**$ 338,864**	**$ (69,446)**	-20.5%
Total Direct Expenses	**$ 572,143**	**$ 1,318,643**	**$ (746,500)**	-56.6%
Indirect Expenses	**$ (572,143)**	**$ (1,318,643)**	**$ 746,500**	-56.6%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ -**	**$ -**	**$ -**	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	$ -	$ -	$ -	
Incr(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B+C)	**-**	**-**	**-**	
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ -**	**$ -**	**$ -**	
FTEs	1.0	7.0	(6.0)	-85.7%

Personnel Expense

- Salaries were lower due to vacancies and the decision to utilize consultants and professional service in lieu of employees.
- Payroll taxes were lower due to lower salaries.
- Benefits were lower due to vacancies and lower than budgeted enrollment in and usage of benefit plans by employees.
- Retirement costs are under budget primarily due to vacancies.

Meeting Expense

- Travel costs were lower due to vacancies and cost savings.

Operating Expenses

- Consultants and contracts were higher to due to the decision to utilize consultants and professional service in lieu of employees.
- Office costs were lower due to cost savings.
- Professional services were higher to due to the decision to utilize consultants and professional service in lieu of employees.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
INFORMATION TECHNOLOGY

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Funding				
Assessments	$ -	$ -	$ -	
Federal Grants	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	$ 440,701	$ 200,356	$ 240,345	120.0%
Payroll Taxes	24,302	13,787	10,515	76.3%
Benefits	16,701	33,515	(16,814)	-50.2%
Retirement Costs	25,773	13,787	11,986	86.9%
Total Personnel Expenses	**$ 507,477**	**$ 261,445**	**$ 246,032**	94.1%
Meeting Expenses				
Meetings	$ 1,920	$ -	$ 1,920	
Travel	8,825	8,400	425	5.1%
Conference Calls	45	4,800	(4,755)	-99.1%
Total Meeting Expenses	**$ 10,790**	**$ 13,200**	**$ (2,410)**	-18.3%
Operating Expenses				
Consultants & Contracts	$ 39,120	$ -	$ 39,120	
Office Rent	-	-	-	
Office Costs	1,989	248,400	(246,411)	-99.2%
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	23,096	-	23,096	
Total Operating Expenses	**$ 64,206**	**$ 248,400**	**$ (184,194)**	-74.2%
Total Direct Expenses	**$ 582,473**	**$ 523,045**	**$ 59,428**	11.4%
Indirect Expenses	**$ (582,473)**	**$ (523,045)**	**$ (59,428)**	11.4%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ -**	**$ -**	**$ -**	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	(23,096)	-	(23,096)	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	$ 23,096	$ -	$ 23,096	
Incr(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B+C)	**-**	**-**	**-**	
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ -**	**$ -**	**$ -**	
FTEs	3.0	3.0	-	0.0%

Personnel Expense

- Salaries were higher due to lower vacancy rates and higher rates of pay than budgeted.
- Payroll taxes were higher due to higher salary expense.
- Benefits were lower due to lower than budgeted enrollment in and usage of benefit plans by employees.
- Retirement costs are over budget primarily due to a higher defined contribution rate than budgeted.

Operating Expenses

- Consultants and contracts was budgeted within the SAIS program but recorded in Information Technology..
- Office costs were lower due to anticipated costs not being incurred.
- Depreciation was budgeted with the SAIS program but recorded in Information Technology.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
HUMAN RESOURCES

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Funding				
Assessments	$ -	$ -	$ -	
Federal Grants	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	$ 368,478	$ 374,152	$ (5,674)	-1.5%
Payroll Taxes	26,906	13,775	13,131	95.3%
Benefits	517,763	496,527	21,236	4.3%
Retirement Costs	29,363	13,775	15,588	113.2%
Total Personnel Expenses	**$ 942,510**	**$ 898,229**	**$ 44,281**	4.9%
Meeting Expenses				
Meetings	$ -	$ -	$ -	
Travel	33,241	10,200	23,041	225.9%
Conference Calls	73	1,000	(927)	-92.7%
Total Meeting Expenses	**$ 33,314**	**$ 11,200**	**$ 22,114**	197.4%
Operating Expenses				
Consultants & Contracts	$ 42,600	$ -	$ 42,600	
Office Rent	37	-	37	
Office Costs	105,336	83,350	21,986	26.4%
Professional Services	33,359	25,000	8,359	33.4%
Miscellaneous	-	-	-	
Depreciation	-	-	-	
Total Operating Expenses	**$ 181,332**	**$ 108,350**	**$ 72,982**	67.4%
Total Direct Expenses	**$ 1,157,156**	**$ 1,017,779**	**$ 139,377**	13.7%
Indirect Expenses	**$ (1,157,156)**	**$ (1,017,779)**	**$ (139,377)**	13.7%
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ -**	**$ -**	**$ -**	
Change in Assets	**$ -**	**$ -**	**$ -**	
Fixed Assets				
Depreciation	-	-	-	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	$ -	$ -	$ -	
Incr(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B+C)	**-**	**-**	**-**	
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ -**	**$ -**	**$ -**	
FTEs	4.0	3.0	1.0	33.3%

Personnel Expense

- Payroll taxes were higher due to higher rates than budgeted.
- Retirement costs are over budget due to higher employee count and due to a higher defined contribution rate than budgeted.

Meeting Expense

- Travel costs were higher than budget due to more frequent travel between locations than budgeted.

Operating Expenses

- Consultants and contracts were higher due to unbudgeted costs for development and compensation studies.
- Office costs were higher than budget due to the cost of computer maintenance and licensing.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
FINANCE AND ACCOUNTING

	2014 Actual	2014 Budget	2014 Variance Over(Under)	Variance %
Funding				
Assessments	$ -	$ -	$ -	
Federal Grants	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ -**	**$ -**	**$ -**	
Expenses				
Personnel Expenses				
Salaries	327,396	$ 332,861	$ (5,465)	-1.6%
Payroll Taxes	26,438	22,889	3,549	15.5%
Benefits	37,951	67,369	(29,418)	-43.7%
Retirement Costs	28,858	22,889	5,969	26.1%
Total Personnel Expenses	**$ 420,642**	**$ 446,008**	**$ (25,366)**	-5.7%
Meeting Expenses				
Meetings	951	$ -	$ 951	
Travel	11,934	15,000	(3,066)	-20.4%
Conference Calls	-	400	(400)	-100.0%
Total Meeting Expenses	**$ 12,885**	**$ 15,400**	**$ (2,515)**	-16.3%
Operating Expenses				
Consultants & Contracts	-	$ -	$ -	
Office Rent	-	-	-	
Office Costs	108,929	85,750	23,179	27.0%
Professional Services	-	86,000	(86,000)	-100.0%
Miscellaneous	-	-	-	
Depreciation	7,539	-	7,539	
Total Operating Expenses	**$ 116,468**	**$ 171,750**	**$ (55,282)**	-32.2%
Total Direct Expenses	**$ 549,995**	**$ 633,158**	**$ (83,163)**	-13.1%
Indirect Expenses	**$ (550,051)**	**$ (633,158)**	**$ 83,107**	-13.1%
Other Non-Operating Expenses	**$ 56**	**$ -**	**$ 56**	
Total Expenses (B)	**$ (0)**	**$ -**	**$ (0)**	
Change in Assets	**$ 0**	**$ -**	**$ 0**	
Fixed Assets				
Depreciation	(7,539)	-	(7,539)	
Computer & Software CapEx	-	-	-	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	-	-	-	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	$ 7,539	$ -	$ 7,539	
Incr(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ -**	
TOTAL BUDGET (B+C)	**(0)**	**-**	**(0)**	
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ 0**	**$ -**	**$ 0**	
FTEs	4.0	5.0	(1.0)	-20.0%

Personnel Expense

- Benefits were lower due to lower than budgeted enrollment in and usage of benefit plans by employees.

Operating Expenses

- Office costs were higher than budget due to the cost of computer maintenance and licensing.
- Professional services were lower due to the lack of auditing work required during 2014. Audit and accounting services will be incurred going forward.

Statement of Activities, Fixed Asset Expenditures
2014 Actual & Budget
NON-STATUTORY

	2014 Actual	2014 Budget	Variance Over(Under)	Variance %
Funding				
Assessments	$ -	$ -	$ -	
Penalty Sanctions	-	-	-	
Non-statutory Funding	1,311,417	-	1,311,417	
Federal Grants	-	-	-	
Workshops	-	-	-	
Interest	-	-	-	
Miscellaneous	-	-	-	
Total Funding (A)	**$ 1,311,417**	**$ -**	**$ 1,311,417**	
Expenses				
Personnel Expenses				
Salaries	273,543	-	$ 273,543	
Payroll Taxes	14,831	-	14,831	
Benefits	27,050	-	27,050	
Retirement Costs	16,940	-	16,940	
Total Personnel Expenses	**$ 332,365**	**$ -**	**$ 332,365**	
Meeting Expenses				
Meetings	-	-	$ -	
Travel	6,576	-	6,576	
Conference Calls	-	-	-	
Total Meeting Expenses	**$ 6,576**	**$ -**	**$ 6,576**	
Operating Expenses				
Consultants & Contracts	$ -	$ -	$ -	
Office Rent	-	-	-	
Office Costs	10,510	-	10,510	
Professional Services	-	-	-	
Miscellaneous	-	-	-	
Depreciation	17,634	-	17,634	
Total Operating Expenses	**$ 28,144**	**$ -**	**$ 28,144**	
Total Direct Expenses	**$ 367,084**	**$ -**	**$ 367,084**	
Indirect Expenses	**$ 113,366**	**$ -**	**$ 113,366**	
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	
Total Expenses (B)	**$ 480,451**	**$ -**	**$ 480,451**	
Change in Assets	**$ 830,966**	**$ -**	**$ 830,966**	
Fixed Assets				
Depreciation	(17,634)	-	(17,634)	
Computer & Software CapEx	80,123	-	80,123	
Furniture & Fixtures CapEx	-	-	-	
Equipment CapEx	58,550	-	58,550	
Leasehold Improvements	-	-	-	
Allocation of Fixed Assets	-	-	$ -	
Incr(Dec) in Fixed Assets (C)	**$ 121,040**	**$ -**	**$ 121,040**	
TOTAL BUDGET (B+C)	**601,490**	**-**	**601,490**	
TOTAL CHANGE IN WORKING CAPITAL (A-B-C)	**$ 709,927**	**$ -**	**$ 709,927**	
FTEs	0.5	-	0.5	

Non-Statutory activities were not anticipated or budgeted in 2014 and therefore all increases were driven by these new activities.

Report of Independent Auditors and
Financial Statements for

Peak Reliability

December 31, 2014

MOSS-ADAMS LLP

Certified Public Accountants | Business Consultants

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REPORT OF INDEPENDENT AUDITORS

To the Board of Directors
Peak Reliability

Report on the Financial Statements

We have audited the accompanying financial statements of Peak Reliability, which comprise the statement of financial position as of December 31, 2014, and the related statements of activities and cash flows for the year then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Peak Reliability as of December 31, 2014, and the changes in its net assets and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated May 26, 2015 on our consideration of Peak Reliability's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering Peak Reliability's internal control over financial reporting and compliance.

Moss Adams LLP

Portland, Oregon
May 26, 2015

PEAK RELIABILITY
STATEMENT OF FINANCIAL POSITION
DECEMBER 31, 2014

ASSETS

Cash and cash equivalents	$ 11,194,764
Accounts receivable	37,208,054
Prepaid expenses and other assets	1,726,017
Property, equipment, and software, net	6,462,733
Total assets	$ 56,591,568

LIABILITIES AND NET ASSETS

LIABILITIES	
Accounts payable	$ 1,109,021
Accrued expenses	2,503,508
Deferred revenue	41,666,546
Other liabilities	117,038
Total liabilities	45,396,113
UNRESTRICTED NET ASSETS	11,195,455
Total net assets	$ 56,591,568

See accompanying notes.

PEAK RELIABILITY
STATEMENT OF ACTIVITIES
FOR THE YEAR ENDED DECEMBER 31, 2014

OPERATING REVENUES	
Reliability coordination funding	$ 30,604,721
Federal grants	323,064
Other	1,315,527
Total operating revenues	32,243,312
OPERATING EXPENSES	
Labor	21,674,970
Office and equipment	7,014,519
Depreciation and amortization	4,140,521
Contract labor and consultants	1,411,968
Meetings	631,318
Professional services	903,079
Other	269,168
Total operating expenses	36,045,543
OPERATING LOSS	(3,802,231)
NON-OPERATING ACTIVITY	
Interest and dividend income	30,836
Net loss on asset disposal	(17,234)
Contribution from WECC	14,984,084
Total non-operating activity	14,997,686
CHANGE IN UNRESTRICTED NET ASSETS	11,195,455
UNRESTRICTED NET ASSETS, beginning of year	-
UNRESTRICTED NET ASSETS, end of year	$ 11,195,455

See accompanying notes.

PEAK RELIABILITY
STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2014

CASH FLOWS FROM OPERATING ACTIVITIES	
Change in unrestricted net assets	$ 11,195,455
Adjustments to reconcile change in unrestricted net assets to net cash from operating activities	
Depreciation and amortization	4,140,521
Loss on disposal of fixed assets	17,234
Net contribution from WECC	(9,172,516)
Changes in assets and liabilities:	
Accounts receivable	(36,552,937)
Prepaid expenses and other assets	(1,525,756)
Accounts payable	1,079,021
Accrued expenses	1,451,616
Deferred revenue	41,666,546
Other liabilities	117,038
Net cash from operating activites	12,416,222
CASH FLOWS FROM INVESTING ACTIVITIES	
Purchase of property, equipment, and software	(1,221,458)
Net cash from investing activites	(1,221,458)
INCREASE IN CASH AND CASH EQUIVALENTS	11,194,764
CASH AND CASH EQUIVALENTS - beginning of year	-
CASH AND CASH EQUIVALENTS - end of year	$ 11,194,764
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION	
Noncash investing activities	
Property and equipment financed with accounts payable	$ 30,000

See accompanying notes.

Note 1 – Nature of Organization and Operations

Peak Reliability (the "Company" or "Peak") is organized and operated exclusively for the best interest of the public welfare. Peak was incorporated on October 10, 2013 and is registered for and fulfills the duties of the Reliability Coordinator and the Interchange Authority, as defined by the North American Electric Reliability Corporation (NERC), and as transferred to it by the Western Electricity Coordinating Council (WECC), for the Company's footprint in the Western Interchange, which includes the Western U.S. and parts of Canada and northern Mexico as its primary activity (see Note 3).

Peak provides real time interconnection-wide oversight of the Bulk Electric System (BES) within the Company's footprint, coordinating necessary real time and seasonal planning and modeling, and ensuring that data critical to the reliable and efficient operation of the BES is shared appropriately. Peak performs additional functions that promote reliability under the BES at the least cost, considering all relevant circumstances and prevailing costs throughout the economy.

The accompanying financial statements reflect the financial position and results of operations for the Company.

Note 2 – Summary of Significant Accounting Policies

Basis of accounting and presentation – The financial statements have been prepared on the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America.

Net assets and revenues, expenses, and gains and losses are classified based on the existence or absence of donor-imposed restrictions. Accordingly, the net assets of the Company and changes therein are classified and reported as follows:

- Unrestricted net assets – reflect the cumulative effect of net activity absent donor-imposed restrictions. There were no temporarily or permanently restricted net assets as of December 31, 2014.

Use of estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used in accounting for, among other things, the allowance for doubtful accounts, the depreciable lives of property, equipment, and software. The Company bases its estimates on historical experience and on various assumptions that are believed to be reasonable under the circumstances at the time. Accordingly, actual results could differ from those estimates under different assumptions or conditions.

Note 2 – Summary of Significant Accounting Policies (continued)

Concentrations – Peak's funding is received from Load Serving Entities (LSE) in the western United States and portions of Canada and Mexico. The three largest LSE's represented 42.2% of Peak's assessment in 2014. The three largest outstanding balances at December 31, 2014 represented 43.7% of the accounts receivable balance at December 31, 2014.

Revenue recognition – Peak recognizes revenue from the statutory funding provided by the NERC for performing the statutory activities that have been sub-delegated to Peak from Western Electricity Coordinating Council (WECC). The annual assessments are collected by WECC and remitted to Peak twice monthly. Peak generally receives assessment payments early during the assessment period and records the assessment as deferred revenue until it is recognized. Assessments are recognized as revenue monthly, in the year they are intended to fund. Federal grant revenue is generated through Peak's and Peak sub-recipient's performance of services in accordance with federal award agreements on a cost reimbursement basis.

Other types of revenues, such as non-statutory revenue, are recognized when the services or products have been provided.

Cash and cash equivalents – For the purposes of the statement of cash flows, Peak considers all highly-liquid investments purchased with an original maturity of three months or less to be cash equivalents. Cash and cash equivalents consist of bank demand accounts, and money market investment accounts. Peak's cash deposits are held with financial institutions in the United Stated that are insured by the Federal Deposit Insurance Corporation (FDIC). Deposits may exceed the federally insured limits at times.

Accounts receivable – Accounts receivable consists of statutory funding, grants and other fees receivable that have not been collected. Accounts receivable are carried at original invoice amount less an estimate made for doubtful receivables based on a review of all outstanding amounts on an annual basis. Management determines the allowance for doubtful accounts by identifying troubled accounts and by using historical experience applied to an aging of accounts. Accounts receivable are written off when deemed uncollectible. Recoveries of accounts receivable previously written off are recorded when received. As of December 31, 2014, there was no allowance for doubtful accounts.

Property, equipment, and software – Expenditures for property, equipment, and software that exceed $5,000 on an individual basis are capitalized at cost and are depreciated using the straight-line method over the estimated useful lives of the assets as follows:

Equipment and software	3 years
Furniture and fixtures	5 years

Leasehold improvements are depreciated over the shorter of the lease term or their estimated useful life of 10 years. Minor replacements, maintenance, and repairs which do not increase the useful lives of the property, equipment, and software to which they are related are expensed as incurred.

Note 2 – Summary of Significant Accounting Policies (continued)

Accrued vacation – Peak accrues accumulated unpaid vacation as the obligation is incurred. Compensated absences are included in "accrued expenses" on the accompanying statement of financial position.

Income taxes – Peak is expected to be recognized by the Internal Revenue Service as a not-for-profit corporation as described in Section 501(c)(4) of the Internal Revenue Code and, as such, is not subject to federal or state income taxes on exempt purpose income. Peak recognized no unrelated business income tax benefit or expense in the year ended December 31, 2014.

Peak has identified and evaluated its significant tax positions for which the statute of limitations remain open. Peak was incorporated in 2013; therefore, open tax years are the years ended December 31, 2013 and 2014 for federal tax purposes and Utah tax purposes. Peak applied the more likely than not criteria to all tax positions and determined that no material unrecognized tax benefits or liability should be recognized. In addition, there have been no material changes in unrecognized benefits as of December 31, 2014, and it is not expected that there will be a material change in the 12 months following December 31, 2014. Peak has not incurred any income tax penalties or related interest expenses during the year ended December 31, 2014.

Functional allocation of expenses – The costs of programs and supporting services have been summarized on a functional basis. Peak's expenses are classified as Statutory Expenses or Non-statutory Expenses as the majority of expenses incurred fulfill the purposes or mission for which Peak exists. Furthermore, the statutory expenses are classified according to the statutory functions Peak performs pursuant to the Sub-Delegation Agreement with WECC. All direct costs are charged to the functional area to which they pertain. Indirect costs are charged to programs and supporting services based on estimates made by management, taking into account the nature of the expense and how it relates to the functional area.

Subsequent events – Subsequent events are events or transactions that occur after the statement of financial position date but before financial statements are issued. The Company recognizes in the financial statements the effects of all subsequent events that provide additional evidence about conditions that existed at the date of the statement of financial position, including the estimates inherent in the process of preparing the financial statements. The Company's financial statements do not recognize subsequent events that provide evidence about conditions that did not exist at the date of the statement of financial position but arose after the statement of financial position date and before financial statements are available to be issued.

Peak has evaluated subsequent events through May 26, 2015 which is the date the financial statements were issued.

Note 3 – WECC Asset Transfer

Peak was incorporated on October 10, 2013, as a subsidiary of WECC in preparation for legal separation of the Reliability Coordinator function from WECC. On January 1, 2014, Peak began operating as a wholly-owned subsidiary and on February 12, 2014, formal Federal Energy Regulatory Commission (FERC) approval of the separation and sub-delegation of the Reliability Coordinator functions was granted, at which time, Peak began operating as an independent not-for-profit Corporation. Effective January 2, 2014 WECC transferred assets related to the reliability function to Peak pursuant to an asset transfer agreement. Included in the amounts transferred from WECC were federal grants totaling $652,933.

Total assets, liabilities and net assets transferred on January 2, 2014 are as follows:

ASSETS	
Cash	$ 5,811,568
Accounts receivable	655,118
Prepaid expenses	200,261
Property, equipment, and software, net	9,369,029
Total assets	$ 16,035,976
LIABILITIES	
Accrued PTO	$ 680,695
Deferred rent	371,197
Total liabilities	1,051,892
UNRESTRICTED NET ASSETS	14,984,084
Total net assets	$ 16,035,976

Note 4 – Property, Equipment, and Software

Property, equipment, and software consisted of the following as of December 31, 2014:

Equipment	$ 9,868,153
Software	7,973,899
Leashold improvements	5,514,891
Furniture and fixtures	232,132
Total property, equipment, and software	23,589,075
Less accumulated depreciation and amortization	(17,839,486)
Construction in progress	713,144
Total property, equipment, and software, net	$ 6,462,733

Depreciation and amortization expense for the year ended December 31, 2014 was $4,140,521.

Assets purchased with grant funds are secured by a lien on the assets. For the year ended December 31, 2014 those assets totaled $4,147,046 (including assets transferred from WECC), net of accumulated depreciation.

Note 5 – Unrestricted Net Assets

Peak reports information regarding statutory and non-statutory related earnings to the FERC in accordance with its Sub-Delegation Agreement with WECC dated February 12, 2014. As of December 31, 2014, the breakdown of those earnings included in unrestricted net assets consisted of the following:

Non-statutory earnings	$ 830,966
Statutory earnings	10,364,489
	$ 11,195,455

Note 6 –Commitments and Contingencies

Operating lease commitments – Peak is party to non-cancelable operating leases for office space and office equipment. Future minimum lease payments, including any escalation clauses, under non-cancelable operating leases with terms of one year or more are as follows:

2015	$ 1,096,056
2016	1,123,419
2017	1,140,573
2018	1,138,878
2019	910,993
	$ 5,409,919

Total rent expense under non-cancelable operating leases was $1,147,504 for the year ended December 31, 2014.

Maintenance and licensing commitments – Peak has entered into several software maintenance and licensing agreements. Future minimum maintenance and licensing commitments, including enterprise licenses, maintenance contracts, support service agreements, and milestone payments for software under development with terms of one year or more are as follows:

2015	$ 3,753,564
2016	2,942,880
2017	2,784,401
2018	1,955,272
2019	1,827,305
Thereafter	1,215,550
	$ 14,478,972

Peak expects to continue to enter into new maintenance and licensing agreements in the future. The extent and cost of these future agreements are not currently known or able to be reasonably estimated and therefore have not been included in the above schedule.

Other matters – Peak may incur future losses from monetary penalties assessed by its regulators. The amounts of monetary penalties associated with regulatory action are uncertain. During 2014, Peak accrued $60,000 for an expected penalty associated with regulatory action. Peak and its regulator have agreed on the amount and Peak expects to receive an invoice and pay the penalty in mid-2015.

Note 7 –Retirement Plan

Employee benefit plan – Peak has a 401(k) Retirement Savings Plan (Plan) for eligible employees. The Plan requires Peak to make matching contributions equal to 50% of the first 6% of eligible compensation of the participating employees' contributions to the Plan. Peak may also make, at its discretion, supplemental contributions for eligible employees. Plan expenses reflected in the accompanying statement of activities was $1,356,422 for the year ended December 31, 2014.

Note 8 –Functional Expenses

The detail of functional expenses for the year ended December 31, 2014 is as follows:

Program services	
Statutory services	$ 27,329,160
Non-statutory services	480,451
	27,809,611
Support services	
Management and general	8,235,932
Total operating expenses	$ 36,045,543

Note 9 – Related Parties

Peak's related party consists of Peak's previous parent company, WECC. WECC was Peak's parent company until the February 12, 2014 order from FERC approving bifurcation.

Transactions with WECC included vendor payments made on Peak's behalf in 2013 and early 2014 for expenses recorded in 2014. For example, 12-month license renewals were paid by WECC in 2013 and lease payments on facilities that were due January 1st were paid by WECC on Peak's behalf. By February of 2014, no further vendor payments were made by WECC on Peak's behalf. In total, approximately $920,000 of expenses were paid by WECC on behalf of Peak, with approximately $720,000 of those expenses reimbursed back to WECC upon bifurcation.

WECC provides billing services on behalf of Peak. This service involves creating and submitting billing invoices to entities assessed under the FERC 215 funding process pursuant to amounts approved by FERC, as well as collection of the cash billed to those entities and subsequent remittance of that cash to Peak. WECC remits cash collected on these invoice billings to Peak on a bi-weekly basis. Amounts in accounts receivable that were billed by WECC through this billing process at December 31, 2014 amounted to $32.8 million.

Note 10 – Concentration of Labor Risk

For the year ended December 31, 2014, approximately 24.6% of the Company's employee base consisted of employees who are subject to a collective bargaining agreement. The International Brotherhood of Electrical Workers – Local 111 represents the Company's entire unionized workforce. The collective bargaining agreement expires on September 15, 2016.

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REPORT OF INDEPENDENT AUDITORS ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS*

To the Board of Directors
Peak Reliability

We have audited, in accordance with the auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States, the financial statements of Peak Reliability, which comprise the statement of financial position as of December 31, 2014, and the related statements of activities and cash flows for the year then ended, and the related notes to the financial statements, and have issued our report thereon dated May 26, 2015.

Internal Control over Financial Reporting

In planning and performing our audit of the financial statements, we considered Peak Reliability's internal control over financial reporting (internal control) to determine the audit procedures that are appropriate in the circumstances for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of Peak Reliability's internal control. Accordingly, we do not express an opinion on the effectiveness of Peak Reliability's internal control.

A *deficiency in internal control* exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct, misstatements on a timely basis. A *material weakness* is a deficiency, or a combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis. A *significant deficiency* is a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

Our consideration of internal control was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies. Given these limitations, during our audit we did not identify any deficiencies in internal control that we consider to be material weaknesses. However, material weaknesses may exist that have not been identified.

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REPORT OF INDEPENDENT AUDITORS ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS* (continued)

Compliance and Other Matters

As part of obtaining reasonable assurance about whether Peak Reliability's financial statements are free from material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards.*

Purpose of this Report

The purpose of this report is solely to describe the scope of our testing of internal control and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the entity's internal control or on compliance. This report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the entity's internal control and compliance. Accordingly, this communication is not suitable for any other purpose.

Moss Adams LLP

Portland, Oregon
May 26, 2015

ATTACHMENT 11

METRICS CONCERNING ADMINISTRATIVE COSTS IN 2014 NERC AND REGIONAL ENTITY BUDGETS AND ACTUAL COSTS

Analysis of Administrative (Indirect) Costs
2014 Actual and Budget

2014 ACTUAL SPEND

	Total Statutory Expenses & Capital Expenditures	Total Statutory Direct Expenses & Capital Expenditures	Total Statutory Indirect Expenses & Capital Expenditures	% Statutory Indirect to Total Statutory	Statutory Direct Spend per Spend on Indirect
NERC	$ 54,691,400	$ 29,363,275	$ 25,328,125	46.31%	$ 1.16
FRCC	6,000,323	5,392,738	607,585	10.13%	8.88
MRO	9,614,099	5,738,225	3,875,874	40.31%	1.48
NPCC	14,603,378	9,318,451	5,284,927	36.19%	1.76
RFC	19,662,681	12,169,645	7,493,036	38.11%	1.62
SERC	15,543,014	8,558,961	6,984,053	44.93%	1.23
SPP RE	9,818,192	4,681,698	5,136,494	52.32%	0.91
Texas RE	9,831,713	6,185,472	3,646,241	37.09%	1.70
WECC	25,438,046	16,428,769	9,009,277	35.42%	1.82
TOTAL/Average	$ 165,202,846	$ 97,837,234	$ 67,365,612	40.78%	$ 1.45

2014 BUDGET SPEND

	Total Statutory Expenses & Capital Expenditures	Total Statutory Direct Expenses & Capital Expenditures	Total Statutory Indirect Expenses & Capital Expenditures	% Statutory Indirect to Total Statutory	Statutory Direct Spend per Spend on Indirect
NERC	$ 56,390,099	$ 31,154,626	$ 25,235,473	44.75%	$ 1.23
FRCC	$ 6,794,932	$ 6,172,992	$ 621,940	9.15%	9.93
MRO	$ 9,744,799	$ 5,774,572	$ 3,970,227	40.74%	1.45
NPCC	$ 14,129,006	$ 9,095,248	$ 5,033,758	35.63%	1.81
RFC	$ 18,063,202	$ 12,869,165	$ 5,194,037	28.75%	2.48
SERC	$ 16,877,288	$ 10,610,814	$ 6,266,474	37.13%	1.69
SPP RE	$ 11,823,629	$ 5,736,162	$ 6,087,467	51.49%	0.94
Texas RE	$ 11,771,251	$ 7,653,236	$ 4,118,015	34.98%	1.86
WECC	$ 25,638,085	$ 16,296,214	$ 9,341,871	36.44%	1.74
TOTAL/Average	$ 171,232,291	$ 105,363,029	$ 65,869,262	38.47%	$ 1.60

2014 ACTUAL FTEs

	Total Statutory FTEs	Total Statutory Direct FTEs	Total Statutory Indirect FTEs	Indirect FTE as % of Total FTE	# Direct to Indirect Statutory FTEs
NERC	177.31	111.31	66.00	37.22%	1.69
FRCC	25.59	22.44	3.15	12.31%	7.12
MRO	39.59	28.94	10.65	26.90%	2.72
NPCC	36.28	27.28	9.00	24.81%	3.03
RFC	69.23	55.48	13.75	19.86%	4.03
SERC	67.38	45.77	21.61	32.07%	2.12
SPP RE	29.41	24.91	4.50	15.30%	5.54
Texas RE	52.00	40.50	11.50	22.12%	3.52
WECC	117.80	79.30	38.50	32.68%	2.06
TOTAL/Average	614.59	435.93	178.66	29.07%	2.44

2014 BUDGET FTEs

	Total Statutory FTEs	Total Statutory Direct FTEs	Total Statutory Indirect FTEs	Indirect FTE as % of Total FTE	# Direct to Indirect Statutory FTEs
NERC	189.53	130.39	59.14	31.20%	2.20
FRCC	30.40	27.04	3.36	11.05%	8.05
MRO	40.75	29.79	10.96	26.90%	2.72
NPCC	36.86	27.86	9.00	24.42%	3.10
RFC	72.00	57.20	14.80	20.56%	3.86
SERC	79.20	59.37	19.83	25.04%	2.99
SPP RE	33.86	30.86	3.00	8.86%	10.29
Texas RE	60.00	49.25	10.75	17.92%	4.58
WECC	135.00	88.10	46.90	34.74%	1.88
TOTAL/Average	677.60	499.86	177.74	26.23%	2.81

2014 ACTUAL SPEND per FTE

	Total Statutory	Total Statutory Direct	Total Statutory Indirect	Statutory Indirect Spend per Total FTE
NERC	$ 308,451	$ 263,797	$ 383,759	$ 142,847
FRCC	234,479	240,318	192,884	23,743
MRO	242,842	198,280	363,932	97,900
NPCC	402,519	341,585	587,214	145,671
RFC	284,020	219,352	544,948	108,234
SERC	230,677	186,999	323,186	103,652
SPP RE	333,839	187,945	1,141,443	174,651
Texas RE	189,071	152,728	317,064	70,120
WECC	215,943	207,172	234,007	76,479
TOTAL/Average	$ 268,802	$ 224,433	$ 377,060	$ 109,611

2014 BUDGETED SPEND per FTE

	Total Statutory	Total Statutory Direct	Total Statutory Indirect	Statutory Indirect Spend per Total FTE
NERC	$ 297,526	$ 238,934	$ 426,707	$ 133,148
FRCC	223,518	228,291	185,101	20,459
MRO	239,136	193,843	362,247	97,429
NPCC	383,315	326,463	559,306	136,564
RFC	250,878	224,985	350,948	72,139
SERC	213,097	178,723	316,010	79,122
SPP RE	349,192	185,877	2,029,156	179,783
Texas RE	196,188	155,396	383,071	68,634
WECC	189,912	184,974	199,187	69,199
TOTAL/Average	$ 252,704	$ 210,785	$ 370,593	$ 97,210

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May 14, 2015

VIA ELECTRONIC FILING

Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: North American Electric Reliability Corporation
Docket No. RR15-___-000
Request for Approval of an Expenditure Greater Than $500,000 from Operating Reserves

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) hereby submits the "Request of the North American Electric Reliability Corporation for Approval of an Expenditure Greater Than $500,000 from Operating Reserves." This request is submitted in accordance with Paragraph 7(b)(ii) of the Settlement Agreement entered into and approved in Docket No. FA11-21-000.

NERC's filing consists of: (1) this transmittal letter, (2) the narrative text of this filing, which follows this transmittal letter, and (3) Attachment 1 to the filing, all of which are being transmitted in a single pdf file.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Owen E. MacBride
Owen E. MacBride

Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
Before the
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)** **)**	**Docket No. RR15-__-000**

REQUEST OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AN EXPENDITURE GREATER THAN $500,000 FROM OPERATING RESERVES

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May 14, 2015

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Attachment 1: Actual and Planned Expenditures for the Corporate Document Management Program Project, 2014 through 2017

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC"), in accordance with Paragraph 7(b)(ii) of the Settlement Agreement in Docket No. FA11-21-000 ("Paragraph 7(b)(ii)"), submits for Commission review and approval a proposed expenditure in excess of $500,000 from NERC's unforeseen contingencies Operating Reserve.[1]

Specifically, NERC requests approval of a proposed expenditure of up to $600,000 from Operating Reserves during 2015 for expedited development and implementation of a centralized corporate document management program. For reasons described herein, including the results and recommendations of an evaluation completed in early 2015, NERC seeks to spend up to $913,000 during 2015 to expedite development and implementation of the document management program. As described herein, the implementation of the document management program is critical to supporting a number of important business requirements which are central to NERC's operations. NERC plans to use $200,000 of funds budgeted in its 2015 Information Technology ("IT") budget for Computer & Software CapEx, $50,000 of funds budgeted in its 2015 IT budget for Office Costs – Computer Supplies and Maintenance, and $63,000 of funds budgeted in its 2015 IT budget for Consultants & Contracts – Application Enhancements, Consulting and Help Desk Support, for this project in 2015.[2] For the additional funding needed, NERC seeks to spend up to $600,000 from Operating Reserves during 2015 on this project.[3]

NERC's current Working Capital and Operating Reserves ("WCOR") Policy requires that expenditures in excess of $500,000 from the Operating Reserve for unforeseen contingencies must be approved by the NERC Board of Trustees, after notice to and

[1] *See North American Electric Reliability Corporation*, 142 FERC ¶61,042 (2013).

[2] NERC's 2015 Business Plan and Budget was filed with the Commission as Attachment 2 to NERC's 2015 Business Plan and Budget Filing in Docket No. RR14-6-000 (filed August 22, 2014).

[3] Additional planned expenditures for the project during 2016 and 2017 will be included in NERC's business plans and budgets for those years that are submitted to the Commission for approval pursuant to 18 C.F.R. §39.4(b).

recommendation by the Finance and Audit Committee ("FAC") of the NERC Board.[4] The proposed expenditure from Operating Reserves was approved by the NERC Board on May 7, 2015, following a recommendation made by the FAC on May 6, 2015. Paragraph 7(b)(ii) specifies that NERC will file for Commission review and approval any Board-approved proposals to expend $500,000 or more from unforeseen contingencies Operating Reserves for any one specific project. Paragraph 7(b)(ii) further specifies that the filing will be deemed approved if the Commission does not act on it or issue a tolling order extending the time for Commission action within thirty days of the filing date.

II. NOTICES AND COMMUNICATIONS

Notices and communications concerning this filing may be addressed to:[5]

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[4] NERC's current WCOR Policy was submitted to the Commission as Attachment 1 to NERC's November 22, 2013 compliance filing on NERC's 2014 Business Plan and Budget filing in Docket No. RR13-9-000. *Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 23 of November 1, 2013 Commission Order*, filed November 22, 2013 in Docket No. 13-9-001. The Commission accepted the November 22, 2013 compliance filing in a letter order issued January 3, 2014 in Docket No. RR13-9-001. Presently pending before the Commission, in Docket No. RR15-8-000, is a proposed revision to NERC's WCOR Policy, filed on March 6, 2015.

[5] Persons to be included on the Commission's official service list are identified by an asterisk. NERC respectfully requests a waiver of the Commission's regulations at 18 C.F.R. §385.203(b)(3) to allow the inclusion of more than three persons on the service list on behalf of NERC in this proceeding.

III. DESCRIPTION OF THE PROPOSED EXPENDITURE FROM OPERATING RESERVES

Paragraph 7(b)(ii) of the Settlement Agreement in Docket No. FA11-21-000 states:

> NERC will file for Commission review and approval Board-of-Trustees-approved proposals to expend $500,000 or more from operating reserves designated for "unforeseen contingencies" (as that term is defined in NERC's Working Capital and Operating Reserve Policy (Reserve Policy)). Each such filing will include supporting materials in sufficient detail to justify the proposed expenditure. The filing will be deemed approved if the Commission does not act on it or issue a tolling order extending the time for Commission action within thirty days of the filing date.
>
> [T]his requirement for Commission review and approval is triggered if any amount allocated from the unforeseen contingencies account of operating reserves plus any amount redirected from previously budgeted funds is, in the aggregate, $500,000 or more for any one specific project or major activity in a program area.

At present, NERC does not have a corporate-wide document management program for creation, editing, sharing, storage, maintenance, and orderly destruction of documents created and/or maintained by NERC and its employees. Documents created or received by NERC employees are processed and maintained on a number of disparate systems, including individual employee computers and shared corporate drives, with no centralized corporate sharing, editing, storage and maintenance capability and no centralized oversight. NERC management determined that a consultant should be retained to evaluate options, benefits and costs for development of a centralized corporate document management program. NERC management conducted a competitive solicitation of proposals for this consulting engagement. A nationally-recognized consulting firm with extensive experience in assisting a wide variety of public and privately-held companies in successfully implementing document management programs was retained to assist in the evaluation.

The evaluation of document management program options, costs and benefits was completed early in 2015. Detailed results and recommendations of the evaluation, including a proposed project plan and funding requirements, were presented by management to the Standards Oversight and Technology Committee of the NERC Board and to the FAC, at

meetings on May 6, 2015.

Implementation of a centralized corporate document management program will address a number of internal audit recommendations relating to information security and will support a number of important business requirements for NERC's operations, including the following: (1) information access and search capabilities; (2) facilitating working group, team and stakeholder collaboration; (3) version control of documents; (4) workflow control (review and approval of documents); (5) simplification of document retrieval; (6) proper classification and management of confidential information; (7) creation and maintenance of audit trails; and (8) adherence to document retention policy and procedures. Implementation of the document management program will increase efficiency and employee productivity and will mitigate corporate risk. The document management program envisioned by the evaluation will include features for document classification, document access, document retention, document sharing, collaboration and versioning, document work flow and audit trail. The development and implementation project will include program design, hardware and software procurement, and installation, as well as development of management oversight policies and employee training and communications.

Implementation of the centralized corporate document management program will be a multi-year project, with significant funding requirements. **Attachment 1** to this filing shows the actual and proposed expenditure requirements for this project in 2014, 2015, 2016 and 2017. The projected total expenditures over the four-year period are $2,211,000, comprised of $1,746,000 of capital expenditures and $465,000 of operating expenses based on applicable capitalization policies. The planned expenditures include $1,861,000 in professional services fees and related expenses for design, development, installation and implementation (including employee training and communications) of the document management program; $200,000 of

hardware and software purchases from vendors; and $150,000 for maintenance and support.[6] The evaluation determined that the projected cost of implementing the document management program, in terms of average cost per user, is comparable to the costs incurred by a comparison group of U.S. utilities. NERC plans to use recognized industry consultants and technology providers for the project. NERC believes that exposure to financial risk due to potential cost overruns on the project is limited because the majority of the consulting costs are contractually capped and the hardware and software costs are known in advance.

In 2014, $208,000 was expended on this initiative; NERC proposes to expend the balance needed to complete the project in 2015 through 2017. As noted earlier, NERC is planning to use for this initiative a total of $313,000 of budgeted funds from its 2015 IT budget, which was developed during 2014 and submitted to the Commission in August 2014, prior to the document management program evaluation being completed. Based on the results of the evaluation completed in early 2015 and the significant benefits of implementing a centralized corporate document management program, management has recommended, and the FAC and Board have concurred, that the project should proceed as soon as possible. In order to proceed with development and implementation of the document management program, significant unbudgeted expenditures will be required during 2015. The plan developed by management in consultation with the consultant provides for the expenditure of approximately $913,000 during 2015 for hardware, software and consulting support to stand up the document management program and to provide initial training. The planned 2015 activities and expenditures will enable the document management program to be operational by the end of 2015. To this end, on May 7, 2015, the NERC Board, following the recommendation of the FAC, authorized the expenditure of up to $600,000 from Operating Reserves on the project during 2015 in accordance with

[6] To be clear, this filing is not requesting Commission approval for the total project expenditures, but rather only for the expenditure in 2015 of up to $600,000 from Operating Reserves on the project.

management's plan.[7]

NERC's approved 2015 Business Plan and Budget provides for $2,000,000 for the unforeseen contingencies Operating Reserve.[8] As reported in NERC's most recent quarterly variance report for the period ended March 31, 2015,[9] the balance in the Operating Contingency Reserve was $2,497,392 as of that date; and NERC management projects a balance of approximately $2.65 million in the Operating Contingency Reserve at year-end 2015 (absent the expenditure proposed herein). NERC management has therefore determined that up to $600,000 can be expended from the Operating Contingency Reserve in 2015 without adversely impacting the 2015 working capital and contingency reserves budget.

Based on the foregoing explanation and justification of the document management program project and proposed expenditures on the project from Operating Reserves in 2015, and in accordance with Paragraph 7(b)(ii), NERC requests the Commission's approval to expend up to $600,000 from the unforeseen contingencies Operating Reserve during 2015 on the document management program project. As provided in Paragraph 7(b)(ii), the proposed expenditure from Operating Reserves will be deemed approved if the Commission does not act on it or issue a tolling order extending the time for Commission action within thirty days of May 15, 2015.

IV. CONCLUSION

For the reasons set forth herein, the North American Electric Reliability Corporation respectfully requests the Commission's approval of the proposed expenditure during 2015 of up

[7] Additional expenditures during 2016 and 2017 will support the integration of all departments of NERC into the document management program on a phased basis through 2017. Details of the planned 2016 and 2017 expenditures will be provided in NERC's business plans and budgets submitted to the Commission for those years.

[8] *See* Exhibit E to NERC's 2015 Business Plan and Budget, Attachment 2 to NERC's August 22, 2014 filing in Docket No. RR14-6-000.

[9] Available at: http://www.nerc.com/gov/bot/FINANCE/2013%20Finance%20and%20Audit%20Committee%20DL/FAC_Agenda_Package_May_6_2015.pdf. *See* pages 11-12.

to $600,000 from NERC's unforeseen contingencies Operating Reserve on the document management program project described herein.

Respectfully submitted,

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ATTACHMENT 1

ACTUAL AND PLANNED EXPENDITURES

FOR THE

CORPORATE DOCUMENT MANAGEMENT PROGRAM PROJECT

2014 THROUGH 2017

ACTUAL AND PLANNED EXPENDITURES
FOR THE
CORPORATE DOCUMENT MANAGEMENT PROGRAM PROJECT
2014 THROUGH 2017
(Dollars)

Item	2014 CapEx	2014 OpEx	2015 CapEx	2015 OpEx	2016 CapEx	2016 OpEx	2017 CapEx	2017 OpEx
Professional Services	208,000		538,000	125,000	465,000	135,000	335,000	55,000
Hardware & Software			200,000					
Maintenance & Support				50,000		50,000		50,000
Subtotal	208,000		738,000	175,000	465,000	185,000	335,000	105,000
Year Total	208,000		913,000		650,000		440,000	

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS PRC-004-5 AND PRC-010-2

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June 8, 2015

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Exhibit A Proposed Reliability Standards

Exhibit A-1 Proposed Reliability Standard PRC-004-5

Exhibit A-2 Proposed Reliability Standard PRC-010-2

Exhibit B Implementation Plans

Exhibit C Order No. 672 Criteria

Exhibit D Mapping Document

Exhibit E Analysis of Violation Risk Factors and Violation Security Levels

Exhibit E-1 Analysis of Violation Risk Factors and Violation Severity Levels for Proposed Reliability Standard PRC-004-3

Exhibit E-2 Analysis of Violation Risk Factors and Violation Severity Levels for Proposed Reliability Standard PRC-010-1

Exhibit F Summary of Development History and Complete Record of Development

Exhibit G Standard Drafting Team Roster

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS PRC-004-5 AND PRC-010-2

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby requests Commission approval of proposed Reliability Standards PRC-004-5 (*Protection System Misoperation Identification and Correction*) (Exhibit A-1) and PRC-010-2 (*Undervoltage Load Shedding*) (Exhibit A-2). The proposed Reliability Standards address Misoperation of undervoltage load shedding ("UVLS") equipment.[4] These standards were developed as Phase 2 of NERC's pending proposal to consolidate UVLS Program Reliability Standards, pursuant to the Commission's directive that NERC develop modifications to PRC-010-0 to require an integrated and coordinated approach in all protection systems.[5] The NERC Board of Trustees adopted proposed Reliability Standards PRC-004-5 and PRC-010-2 on May 7, 2014.

---

1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2014).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 Unless otherwise designated, capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary of Terms"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf. "UVLS Program" and "Remedial Action Scheme" are defined herein, as proposed in Docket Nos. RM15-12-000 and RM15-13-000. *See infra* n. 7.

5 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218, P 1509 (2007). *See infra* Section III.C (discussing the history of the proposed Reliability Standards) and Section V

NERC requests that the Commission approve proposed Reliability Standards PRC-004-5 and PRC-010-2, and find them just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests approval of the Implementation Plans for the proposed Reliability Standards (Exhibit B). The proposed revisions do not affect the Violation Risk Factors ("VRFs") or Violation Severity Levels ("VSLs") associated with the Reliability Standards subject to this petition (attached for reference at Exhibit E).[6] NERC requests that the Commission accept the proposed Reliability Standards effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the proposed Reliability Standards PRC-004-5 and PRC-010-2 are approved. In addition, as discussed in Section V below, NERC respectfully requests that the Commission approve proposed Reliability Standards PRC-004-5, PRC-010-1, and PRC-010-2, as well as pending Reliability Standard EOP-011-1 and the revised definitions of UVLS Program and Remedial Action Scheme concurrently so that the implementation and effective dates align as proposed, because the proposals reflect an integrated and coordinated approach to UVLS Programs.[7]

As required by Section 39.5(a) of the Commission's regulations,[8] this petition presents the technical basis and purpose of proposed Reliability Standards PRC-004-5 and PRC-010-2, a summary of development history (Exhibit F), and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672 (Exhibit C).[9]

(discussing related, pending, proceedings associated with proposed Reliability Standards PRC-004-5, PRC-010-1, PRC-010-2, and EOP-011-1 and the revised definitions of UVLS Program and Remedial Action Scheme).

6 NERC is separately reviewing the VRF associated with PRC-004-3 (included in Exhibit E-1), consistent with the Commission's directive on May 13, 2015. *See N. Am. Elec. Reliability Corp.*, 151 FERC ¶ 61,129 (2015).

7 These listed and pending proposed Reliability Standards and definitional revisions are related. *See infra* Section V and accompanying citations.

8 18 C.F.R. § 39.5(a) (2014).

9 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability*

I. EXECUTIVE SUMMARY

The reliability goals of the proposed Reliability Standards are to ensure that UVLS protective relay Misoperations are identified and corrected, and that UVLS equipment performance is appropriately evaluated. To achieve these goals, and ensure that the planned retirement of currently effective UVLS Reliability Standards does not result in a gap in coverage, the standard drafting team developed the revisions included within proposed Reliability Standards PRC-004-5 and PRC-010-2. As proposed, (i) Reliability Standard PRC-004-5 will revise that standard to be applicable to UVLS that is intended to trip one or more BES Elements, and (ii) PRC-010-2 will reflect revisions to Requirement R4 of that Reliability Standard to expressly require evaluation of UVLS Program equipment performance, with a conforming change to Requirement R5.

The proposed Reliability Standards were developed through Phase 2 of Project 2008-02 to implement an integrated and coordinated approach for UVLS Programs, as embodied in pending Reliability Standard PRC-010-1. In Order No. 693, the Commission directed "the ERO to develop a modification to PRC-010-0 through the Reliability Standards development process that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including … UVLS programs."[10] Proposed Reliability Standard PRC-010-1, pending before the Commission in Docket No. RM15-12-000, represented the standard drafting team's efforts under NERC Project 2008-02 (*i.e.*, Phase 1 of the project) to develop such an integrated and coordinated approach for UVLS Programs. This filing addresses the final item remaining from that earlier phase of the project.

Standards, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at PP 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[10] Order No. 693, at P 1509.

In particular, the proposal for Reliability Standard PRC-010-1 contemplates retirement of currently effective UVLS Program related Reliability Standards, such as Reliability Standard PRC-022-1. Reliability Standard PRC-022-1 includes Requirements that pertain to UVLS Misoperation. Due to coordination with other projects, efforts to address Misoperation of UVLS currently addressed in Reliability Standard PRC-022-1 were segregated to a new phase of UVLS Reliability Standard development entitled Project 2008-02.2, which has led to the development of the proposed Reliability Standards.

Under Project 2008-02.2, the standard drafting team designed a two-pronged approach proposing modifications to Reliability Standards PRC-004-5 and PRC-010-1 to address identification, correction, and evaluation of performance of UVLS Programs and its equipment.[11] Proposed PRC-004-5 addresses protection systems that trip BES interrupting devices (*i.e.*, BES Elements). Performance under proposed Reliability Standard PRC-004-5 is initiated when a BES interrupting device automatically trips or is manually tripped due to a Protection System failure to operate. Proposed Reliability Standard PRC-010-2, on the other hand, addresses review of UVLS equipment and whether UVLS Program equipment performed effectively following an event that resulted in a voltage excursion for which the UVLS Program was designed to operate. Proposed Reliability Standard PRC-010-2, Requirements R4 and R5 were revised to clarify that the assessment to determine whether the UVLS Program resolved the undervoltage issues associated with the relevant event includes an evaluation of UVLS equipment operation.

[11] Note that centrally controlled UVLS is now addressed by the proposed definition of "Remedial Action Scheme" per the proposal pending in Docket No. RM15-12. *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-010-1 (Undervoltage Load Shedding)*, Docket No. RM15-12-000, pp. 16-17 (Feb. 6, 2015). As a result, this petition does not address such centrally controlled UVLS.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[12]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[13] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.[14] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. [15] Section 39.5(a) of the Commission's

[12] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2014), to allow the inclusion of more than two persons on the service list in this proceeding.

[13] 16 U.S.C. § 824o (2012).

[14] *Id.* § 824o(b)(1).

[15] *Id.* § 824o(d)(5).

regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.[16]

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[17] and Section 39.5(c) of the Commission's regulations, "the Commission will give due weight to the technical expertise of the Electric Reliability Organization" with respect to the content of a Reliability Standard.[18]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[19] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[20]

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16 18 C.F.R. § 39.5(a).

17 16 U.S.C. § 824o(d)(2).

18 18 C.F.R. § 39.5(c)(1).

19 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

20 The NERC *Rules of Procedure* are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[21] and thus satisfy certain of the criteria for approving Reliability Standards.[22] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and stakeholders must approve, and the NERC Board of Trustees must adopt a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. History of the Proposed Reliability Standards

As described below, the proposed Reliability Standards were designed by the standard drafting team during the second phase of implementing an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS Programs.

1. Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations

NERC Project 2008-02 was established to modify the UVLS-related Reliability Standards to establish an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS Programs that are used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading on the Bulk Electric System. The standard drafting team for Project 2008-02 aimed to consolidate existing UVLS-related Reliability Standards and eliminate the Regional Reliability Organization as an applicable entity in Reliability Standard PRC-020-1. To achieve those goals, the standard drafting team sought to create a results-based standard clearly defining the responsibilities of applicable entities to:

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21 *N. Am. Elec. Reliability Corp*, 116 FERC ¶ 61,062, at P 250.

22 Order No. 672, at PP 268, 270.

- pursue an integrated and coordinated approach to the design, evaluation, and reliable operation of automatic, distributed UVLS Programs;
- ensure the coordination of automatic, distributed, UVLS Programs with generator voltage ride-through capabilities and protection and control systems; and
- establish proper and meaningful automatic, distributed UVLS database requirements.

In its efforts, the standard drafting team considered input from a variety of sources including the 2003 Blackout Report, Commission guidance in Order No. 693, and recommendations from the NERC System Protection and Control Subcommittee ("SPCS") of the Planning Committee in the December 2010 *NERC SPCS Technical Review of UVLS-Related Standards: PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1* ("SPCS Technical Review").[23] The SPCS Technical Review recommended (among other revisions) differentiating post-event validation of UVLS Program design from verifying correct operation of UVLS equipment.

During the development of PRC-004-3 (Project 2010-05.1 (*System Protection: Misoperations*)) and PRC-010-1 (Project 2008-02 (*Undervoltage Load Shedding (UVLS)*), both standard drafting teams decided that Misoperation of UVLS equipment stemming from the retirement of PRC-022-1 (*Under-Voltage Load Shedding Program Performance*) would be addressed as a later phase of the project. Reliability Standard PRC-022-1 addressed UVLS operation and Misoperation (Requirement R1) and included a provision for mitigating future Misoperations through a Corrective Action Plan (Requirement R1.5). It was decided that this aspect of PRC-022-1 would be accounted for through Project 2008-02.2 – Phase 2 Undervoltage

[23] *See*, http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-010_022%20Report_Approved_20101208.pdf. These standards are discussed in more detail in Section III.C.3.

Load Shedding (UVLS): Misoperations.[24] This phase of the project was initially deferred due to dependencies with other projects being completed.

The reliability goals of Project 2008-02.2 are to ensure that UVLS equipment performance (operation/non-operation) is evaluated and that any Misoperation of UVLS is identified and corrected. Through Project 2008-02.2, the standard drafting team addressed Misoperation of UVLS equipment, through the revisions in proposed Reliability Standards PRC-004-5 and PRC-010-2.

2. **PRC-004-5**

Reliability Standard PRC-004-1 was approved by the Commission in Order No. 693.[25] On April 15, 2011, NERC filed an interpretation of Requirements R1 and R3 of PRC-004-1 and Requirements R1 and R2 of PRC-005-1, which was approved by the Commission on September 26, 2011.[26] PRC-004-2 was approved by the Commission in a letter order issued on January 10, 2011.[27] PRC-004-2.1a was approved by the Commission in Order No. 785.[28] PRC-004-3, which was filed to replace PRC-004-2.1a, was approved by the Commission on May 13, 2015, subject to a compliance filing regarding VRF designations for Requirements R1 through R6 of that Reliability Standard.[29] PRC-004-4 was more recently filed to address dispersed generation

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[24] The Project webpage is available at http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx.

[25] Order No. 693, at P 1467.

[26] *N. Am. Elec. Reliability Corp.*, 136 FERC ¶ 61,208 (2011).

[27] *N. Am. Elec. Reliability Corp.*, 134 FERC ¶ 61,015 (2011).

[28] *See Generator Requirements at the Transmission Interface*, Order No. 785, 144 FERC ¶ 61,221 (2012) (approving PRC-004-2.1a and clarifying that the Requirements in PRC-004 extend not only to protection systems associated with the generating facility or station itself, but also to any protection systems associated with the generator interconnection facilities).

[29] *N. Am. Elec. Reliability Corp.*, 151 FERC ¶ 61,129 (2015).

resources and accepted by the Commission on May 29, 2015.[30] Proposed Reliability Standard PRC-004-5 is intended to replace prior versions of PRC-004.

3. **PRC-010-2**

In Order No. 693, the Commission directed an integrated and coordinated approach to all protection systems.[31] In accordance with this directive, in February of 2015, NERC submitted Reliability Standard PRC-010-1, a revised definition of UVLS Program, and the associated Implementation Plan and VRF and VSLs for Commission approval.[32] NERC also requested retirement of UVLS Reliability Standards PRC-010-0 (*Assessment of the Design and Effectiveness of UVLS Program*); PRC-020-1 (*Under-Voltage Load Shedding Program Database*); PRC-021-1 (*Under-Voltage Load Shedding Program Data*); and PRC-022-1 (*Under-Voltage Load Shedding Program Performance*), as PRC-010-1 addresses the same reliability principles outlined in those standards being retired.[33] NERC's filing for PRC-010-1 noted that one aspect associated with Project 2008-02 remained. As described in Section III.C.1 above, the standard drafting teams determined that the aspect of PRC-022-1 relating to Misoperation of UVLS should be addressed at a later stage, which became Project 2008-02.2.[34] This filing addresses that remaining issue by submitting the proposed Reliability Standards developed under Project 2008-02.2.

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30 *N. Am. Elec. Reliability Corp*, 151 FERC ¶ 61,186 (2015).

31 Order No. 693, at P 1509.

32 *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-010-1 (Undervoltage Load Shedding)*, Docket No. RM15-12-000 (Feb. 6, 2015). *See also*, Section V (describing other proposals associated with implementation of an integrated and coordinated approach to UVLS protection systems).

33 *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-010-1 (Undervoltage Load Shedding)*, Docket No. RM15-12-000, at pp. 1-2 (Feb. 6, 2015).

34 *Id.*, at p. 23.

IV. JUSTIFICATION FOR APPROVAL

As discussed in Exhibit C and below, proposed Reliability Standards PRC-004-5 and PRC-010-2, satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following subsections provide: (A) a description of each proposed standard, its reliability purposes, and applicable entities; (B) justification for each proposed standard, detailing the proposed revisions; and (C) discussion of the enforceability of the proposed standards. As discussed below, the scope of the revisions are consistent with identifying Misoperation of UVLS equipment and the Commission's directive in Order No. 693 for development of an integrated and coordinated approach in UVLS Programs.

A. Proposed Reliability Standard PRC-004-5

1. Purpose of Proposed PRC-004-5 and Applicable Entities

The purpose of proposed Reliability Standard PRC-004-5 is to "[i]dentify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements." The standard applies to Distribution Providers, Generation Owners, and Transmission Owners. Proposed Reliability Standard PRC-004-5 updates prior versions of PRC-004 (*see supra*, Section III.C.2) by reference to UVLS. Proposed Reliability Standard PRC-004-5 improves existing versions of the Reliability Standard by expressly referencing UVLS equipment. Specifically, "Undervoltage load shedding" was added to the Applicability section 4.2 of PRC-004-5 to include UVLS within the scope of the standard.

2. Justification for Proposed Revisions

Based on the analysis regarding the scope of PRC-004 and PRC-010, the standard drafting team proposed one revision to the Applicability of PRC-004-5 to expand the scope of Facilities under the standard, so that the standard would encompass UVLS intended to trip one or

more BES Elements. No changes were made to any specific Requirements or Measures under PRC-004, as the proposed revision ensures that all of the Requirements under the standard become applicable to UVLS equipment. The UVLS revisions described herein and reflected at Applicability, Section 4.2.3 of PRC-004-5 are as follows:[35]

> **4.2. Facilities:**
>
> **4.2.1** Protection Systems for BES Elements, with the following exclusions:
>
> **4.2.1.1** Non-protective functions that are embedded within a Protection System.
>
> **4.2.1.2** Protective functions intended to operate as a control function during switching.2
>
> **4.2.1.3** Special Protection Systems (SPS).
>
> **4.2.1.4** Remedial Action Schemes (RAS).
>
> **4.2.1.5** Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.
>
> **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.
>
> **4.2.3** Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

This modification will require applicable entities to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. PRC-004-5 would initiate a review of UVLS when a BES interrupting device operates per a Protection System or by manual intervention in response to a Protection System failure to operate. Proposed Reliability Standard PRC-004-5 works together with PRC-010-2, because inclusion of UVLS to the Applicability of PRC-004-5 now addresses the operation of UVLS for BES Elements. Where UVLS trips a BES Element, an entity will initiate work under PRC-004. If the entity discovers a Misoperation under PRC-004-5, the entity will develop and implement a Corrective Action Plan for any

[35] *See* Exhibit A-1 for full redline.

known causes of the Misoperation. Action under PRC-004-5 may occur within a narrower time frame than under PRC-010-2, because if a BES interrupting device trips, it must be reviewed timely and any cause of Misoperations mitigated. If a planner under PRC-010-2 discovers a potential Misoperation of UVLS equipment, it would be considered a deficiency in the UVLS Program and be addressed accordingly. As discussed in Section IV.B., the revisions to PRC-010-2 address operation/non-operation of UVLS equipment within a UVLS Program. PRC-010-2 also includes equipment that generally trips equipment classified as BES and equipment not classified as BES.

B. Proposed Reliability Standard PRC-010-2

1. Purpose of Proposed PRC-010-2 and Applicable Entities

The purpose of PRC-010-2 is "[t]o establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs ("UVLS Programs")." Proposed PRC-010-2 would replace pending Reliability Standard PRC-010-1. PRC-010-1 did not explicitly address Misoperation of UVLS Equipment, previously addressed under Reliability Standard PRC-022-1. *See supra,* Section III.C. Proposed Reliability Standard PRC-010-2 updates pending Reliability Standard PRC-010-1 by explicitly addressing the operations/non-operation (i.e., Misoperation) of UVLS Equipment to avoid a gap in coverage due to retirement of Reliability Standard PRC-022-1. The proposed Reliability Standard achieves this by expressly referencing performance (i.e., operation/non-operation) of the UVLS Program equipment at Requirement R4 with a conforming update to Requirement R5 to specifically reference the assessment performed in Requirement R4.[36]

[36] While "Misoperation" as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-10, the term is used in the *PRC-010-2 – Application Guidelines* to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be addressed by UVLS entities. *See* Exhibit A-2, at *PRC-010-2 – Application Guidelines,* Guidelines for Requirement R4.

The proposed Reliability Standard PRC-010-2 applies to Planning Coordinators and Transmission Planners. The standard applies to the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the UVLS Program. The standard drafting team determined that the Planning Coordinator or Transmission Planner is in the best position to assess correct operation of UVLS equipment within the UVLS Program. The planners will have the inputs from the UVLS entities and the tools necessary to determine whether specific UVLS operated correctly according to the design of the UVLS Program. Proposed PRC-010-2 also applies to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Provider and Transmission Owners are referred to as "UVLS entities" within the Applicability section of proposed Reliability Standard PRC-010-2.

2. Justification for Proposed Revisions

The revisions to PRC-010-1 address issues not resolved through the reference to UVLS under PRC-004-5, and which were examined by the standard drafting team as part of Project 2008-02.2. Proposed Reliability Standard PRC-010-2, Requirements R4 and R5 explicitly cover UVLS Program equipment performance and action to address any deficiencies identified in assessment of such performance as follows:[37]

> **R4.** Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate ~~whether its UVLS Program resolved the undervoltage issues associated with the~~ event.: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
>
> **4.1.** Whether its UVLS Program resolved the undervoltage issues associated with the event, and

[37] *See* Exhibit A-2 for full redline, and additional Frequently Asked Questions included within the *PRC-010-1 – Supplemental Material*.

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies ~~in its UVLS Program~~ during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

These revisions require UVLS entities to address any deficiencies (e.g. Misoperations) identified by a Planning Coordinator or Transmission Planner through the assessment performed under revised Requirement R4. Deficiencies include performance (operation/non-operation) issues associated with UVLS Program equipment. Any identified Misoperations are addressed by the UVLS entities through a Corrective Action Plan developed per Requirement R5 by the Planning Coordinator or Transmission Planner, and executed by the UVLS entities pursuant to Requirement R2. The revisions ensure that review of UVLS Program equipment is initiated for an event that resulted in a voltage excursion for which the UVLS Program was designed to operate, and requires the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010. In addition, the assessment addresses the larger issue of whether a UVLS Program was effective following an event that resulted in a voltage excursion for which the UVLS Program was designed to operate. The Planning Coordinator or Transmission Planner will perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

This process ensures that UVLS Program equipment is evaluated for Misoperation. The standard drafting team created two parts of Requirement R4 to clarify that UVLS equipment operations must be evaluated as a part of the assessment to determine whether the UVLS Program resolved the undervoltage issues associated with the event.[38] This is consistent with identifying Misoperation of UVLS equipment, the directive in Order No. 693, and the SPCS Technical Review.

C. Enforceability of The Proposed Reliability Standards

The proposed Reliability Standards include Measures that support each Requirement to help ensure that the Requirements will be enforced in a clear, consistent, non-preferential manner and without prejudice to any party. The proposed Reliability Standards also include VRFs and VSLs for each Requirement. The VSLs and VRFs are part of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standards. The VRFs assess the impact to reliability of violating a specific Requirement.

As the Requirements contained in the proposed Reliability Standards track with those contained in the already approved or pending proposed versions of the Reliability Standards, the standard drafting team determined that the modifications proposed here did not give rise to changes in VSLs and VRFs for the proposed Reliability Standards. For example, the standard drafting team agreed that, originally, the assessment in PRC-010 at Requirement R4 was intended to include UVLS equipment, however, Requirement R4, Part 4.2 was added as discussed above to clarify performance of UVLS equipment explicitly to address any perception

[38] *See also*, Exhibit A-1 and A-2, at *Standard Development Timeline.* In addition to the substantive revisions discussed above, the introductory sections of PRC-004-5 and PRC-010-2 were updated and the prior Background sections in each Reliability Standard was deleted.

that Misoperation of UVLS equipment was not addressed. Thus, partial performance of Requirement R4 of proposed Reliability Standard PRC-010-2 is not permitted, and no modification to VRF or VSLs appropriate.

For reference purposes, Exhibit E includes the detailed analysis of the assignment of VRFs and the VSLs for the proposed Reliability Standards as previously submitted to this Commission in Docket Nos. RM15-12 (for Reliability Standard PRC-010-1, as reflected in Exhibit E-2) and RD14-14-000 (for Reliability Standard PRC-004-3 as reflected in Exhibit E-1). The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines, although NERC notes that it is reviewing VRF designations for PRC-004 consistent with the Commission's directive on May 13, 2015 for PRC-004-3.[39]

V. EFFECTIVE DATE

NERC respectfully requests that the Commission accept proposed Reliability Standards PRC-004-5 and PRC-010-2 effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the proposed Reliability Standards are approved. In addition, NERC respectfully requests that the Commission approve proposed Reliability Standards PRC-004-5, PRC-010-1, and PRC-010-2, as well as pending Reliability Standard EOP-011-1 and the revised definitions of UVLS Program and Remedial Action Scheme concurrently so that the implementation and effective dates align as proposed, because the proposals reflect an integrated and coordinated approach to UVLS Programs.

Concurrent approval and aligned implementation of the proposed Reliability Standards PRC-004-5, PRC-010-1, PRC-010-2, and EOP-010-1 and the revised definitions of UVLS

[39] *N. Am. Elec. Reliability Corp.*, 151 FERC ¶ 61,129 (2015).

Program and Remedial Action Scheme are just and reasonable and necessary due to the following relationships between the proposals:.[40]

- Proposed Reliability Standards PRC-004-5 and PRC-010-2, as filed in this proceeding, relate to proposed Reliability Standard PRC-010-1 by serving as the second phase of Project 2008-02 and filling a gap in coverage for UVLS Programs arising due to the retirement of PRC-022-1 under implementation of PRC-010-1.[41]

- Proposed Reliability Standards PRC-010-1 and the proposed definition of UVLS Program pending under Docket No. RM15-12-000 necessitate approval of the proposed definition of Remedial Action Scheme pending under Docket No. RM15-12-000, because the term Remedial Action Scheme encompasses centrally controlled UVLS, while the term "UVLS Program" excludes it, due to the determination that centrally controlled UVLS schemes are commensurate with Remedial Actions Schemes.[42]

- Proposed Reliability Standards PRC-010-1 necessitates approval of proposed Reliability Standard EOP-011-1 pending in Docket No. RM15-7-000, because (i) EOP-011-1 will retire Reliability Standard EOP-003-2, and (ii) Requirements R2, R4, and R7 of EOP-003-2 map to PRC-010-1 to eliminate identified redundancy between the standards.[43]

As a result, concurrent approval of proposed Reliability Standards EOP-011-1, PRC-010-1, PRC-010-2, and PRC-004-5, together with the pending definitions of UVLS Program and Remedial Action Scheme, is just, reasonable, and necessary to ensure implementation of an integrated and coordinated approach to UVLS Programs without a gap in reliability.

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40 The Implementation Plans reflected in Exhibit B also reflect such a coordinated approach.

41 *See supra*, Section III.C.

42 *See Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-010-1 (Undervoltage Load Shedding)*, Docket No. RM15-12-000, at Exhibit B, pp. 1-2 (Feb. 6, 2015); *and Petition of the North American Electric Reliability Corporation for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards*, Docket No. RM15-13-000 (Feb. 3, 2015).

43 *Id.*; *and EOP-011-1-Emergency Operations*, Docket No. RM15-7-000 (Dec. 29, 201).

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission grant:

- Approval of the proposed Reliability Standards and other associated elements included in Exhibit A;
- Approval of the Implementation Plans included in Exhibit B; and
- Approval for proposed Reliability Standards PRC-004-5 and PRC-010-2 submitted herein, concurrently with proposed Reliability Standards PRC-010-1 and EOP-011-1, and the revised definitions of UVLS Program and Remedial Action Scheme, so that the implementation and effective dates for the proposals align for an integrated and coordinated approach to UVLS Programs.

Respectfully submitted,

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Date: June 8, 2015

Exhibit A

Proposed Reliability Standards

Exhibit A-1

Proposed Reliability Standard PRC-004-5

PRC-004-5 Clean

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-5

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

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[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None**.**

D. Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1- Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC- approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011

[2] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
2	August 5, 2010	Adpoted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revised in Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[3] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[4] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011). Pg. 3.

[5] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx). May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a “Failure to Trip – During Fault” Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one “Failure to Trip – During Fault” Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation

times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

Example 8a: The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

Example 8b: The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: “In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties.” The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device

owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize

that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[8]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). Figure 15: NERC Wide Misoperations by Cause Code. Pg. 22 of 40.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.

> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.
>
> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation)

through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

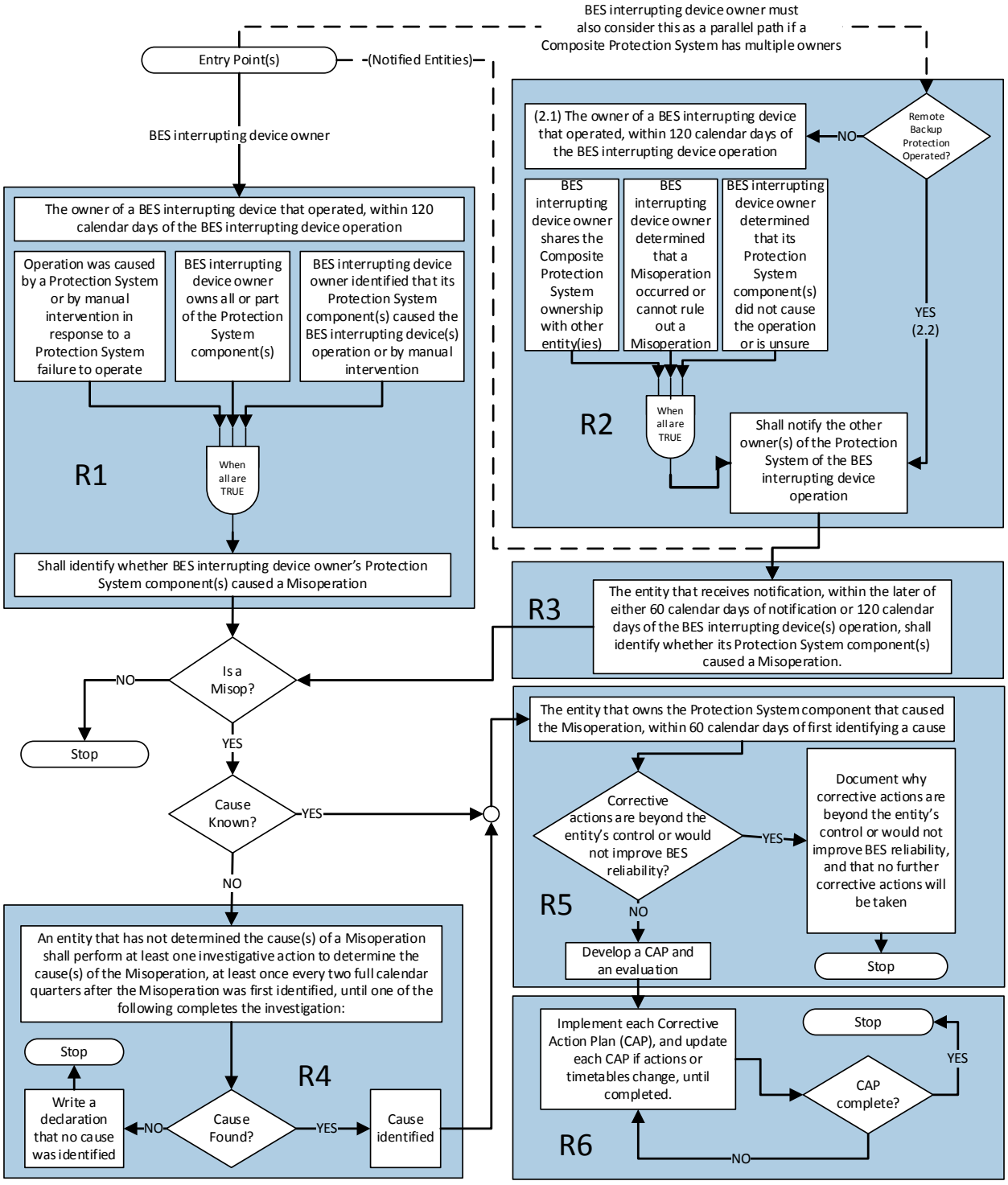
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:


BES interrupting device owner must also consider this as a parallel path if a Composite Protection System has multiple owners
Entry Point(s)
(Notified Entities)
BES interrupting device owner
The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
Operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate
BES interrupting device owner owns all or part of the Protection System component(s)
BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or by manual intervention
R1
When all are TRUE
Shall identify whether BES interrupting device owner's Protection System component(s) caused a Misoperation
(2.1) The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
NO
Remote Backup Protection Operated?
YES (2.2)
BES interrupting device owner shares the Composite Protection System ownership with other entity(ies)
BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation
BES interrupting device owner determined that its Protection System component(s) did not cause the operation or is unsure
R2
When all are TRUE
Shall notify the other owner(s) of the Protection System of the BES interrupting device operation
R3
The entity that receives notification, within the later of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.
Is a Misop?
NO
Stop
YES
Cause Known?
YES
NO
The entity that owns the Protection System component that caused the Misoperation, within 60 calendar days of first identifying a cause
Corrective actions are beyond the entity's control or would not improve BES reliability?
YES
Document why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken
Stop
R5
NO
Develop a CAP and an evaluation
An entity that has not determined the cause(s) of a Misoperation shall perform at least one investigative action to determine the cause(s) of the Misoperation, at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation:
Stop
R4
Write a declaration that no cause was identified
NO
Cause Found?
YES
Cause identified
Implement each Corrective Action Plan (CAP), and update each CAP if actions or timetables change, until completed.
Stop
YES
CAP complete?
NO
R6

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction

The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

Rationale for Applicability

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

PRC-004-5 Redline

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-54

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

~~**5. Background:**~~

~~A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of~~

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

~~Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.~~

~~The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.~~

~~Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.~~

4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

~~6.~~5. Effective Date~~s~~: See Project 2008-02.2 Implementation Plan.

~~See the Implementation Plan for this Standard~~.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1- Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC- approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011

[2] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf-).

Version	Date	Action	Change Tracking
~~2~~		~~Modified to address Order No. 693 Directives contained in paragraph 1469.~~	~~Revised~~
2	August 5, 2010	Adpoted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
~~1a~~	~~February 17, 2011~~	~~Added Appendix 1 – Interpretation regarding applicability of standard to protection of radially connected transformers~~	~~Project 2009-17 interpretation~~
~~1a~~	~~February 17, 2011~~	~~Adopted by NERC Board of Trustees~~	
~~1a~~	~~September 26, 2011~~	~~FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)~~	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees ~~Errata change: Edited R2 to add "…and generator interconnection Facility…"~~	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"~~Revision under Project 2010-07~~
~~2.1a~~	~~February 9, 2012~~	~~Errata change adopted by NERC Board of Trustees~~	
~~2.1a~~	~~September 19, 2013~~	~~FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).~~	

Version	Date	Action	Change Tracking
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revised in Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[3] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[4] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL .pdf. July 2011-). Pg. 3.

[5] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/~~RelaibilityCoordinationProject 20066~~RelaibilityCoordinationProject20066.aspx-). May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** *– A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*

4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.
>
> **Example 1d:** A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.
>
> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated

authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf.). April 1, 2013. pgPg. 37 of 40.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.
>
> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a

Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that

certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[8]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013~~:~~. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf~~-~~). Figure 15: NERC Wide Misoperations by Cause Code. ~~pg~~Pg. 22 of 40.

problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5c: Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.

A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

Example R5d: Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

Example R5e: The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.
>
> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

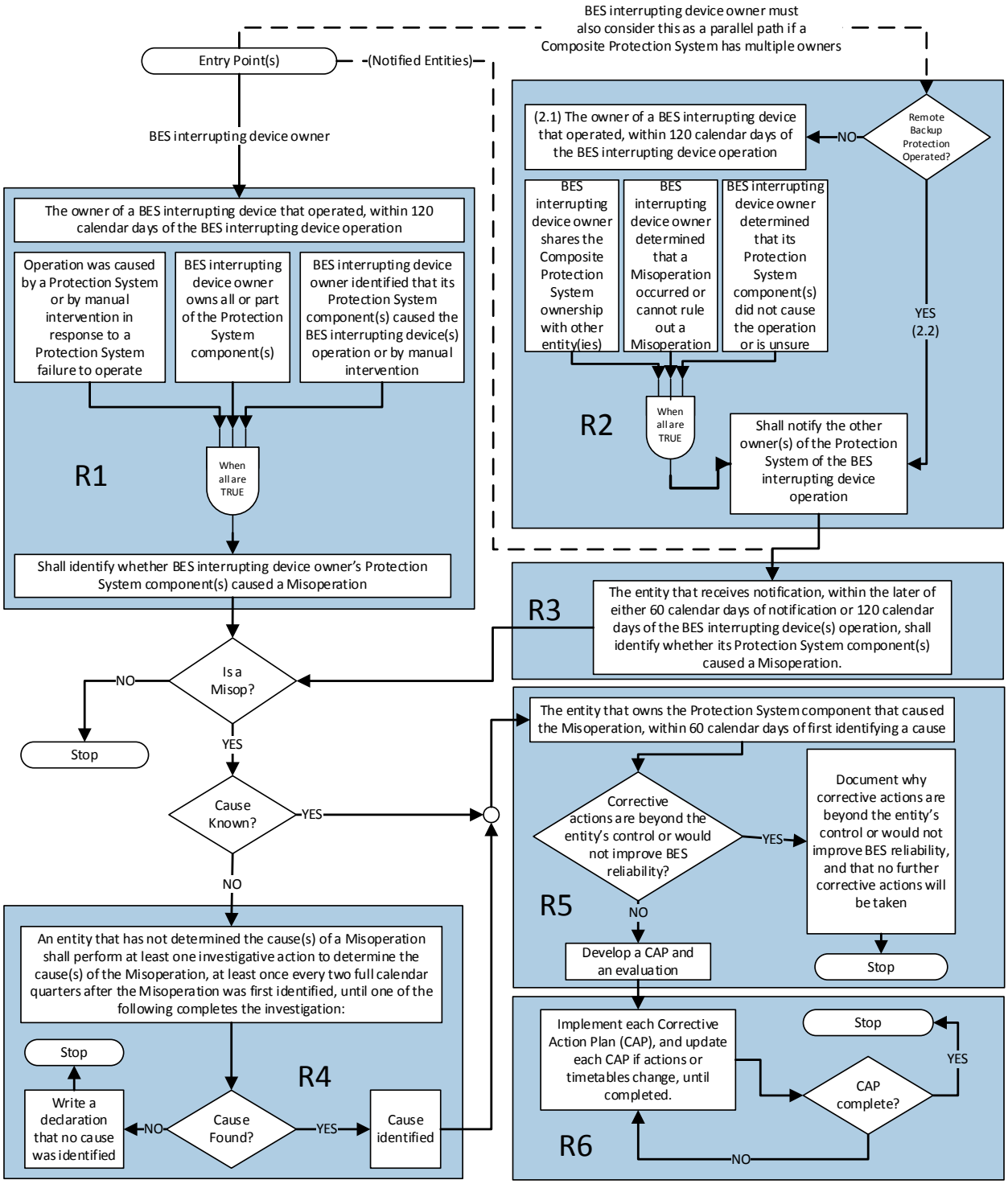
> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Rationale~~:~~

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. ~~-~~Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction~~:~~

The only revisions made to ~~this~~ version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard ~~to~~at generator Facilities.~~-~~ These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

Rationale for Applicability~~:~~

~~Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of Project 2010-05.1 .~~

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. ~~-~~See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000.~~-~~ The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

~~**Rationale for R1:**~~

~~This Requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a~~

~~condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.~~

~~Rationale for R2:~~

~~Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific other owners that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.~~

~~Rationale for R3:~~

~~When an entity receives notification of a Protection System operation by the BES interrupting device owner, the other Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.~~

Exhibit A-2

Proposed Reliability Standard PRC-010-2

A. Introduction

1. **Title:** Undervoltage Load Shedding

2. **Number:** PRC-010-2

3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified

below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2	May 7, 2015	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

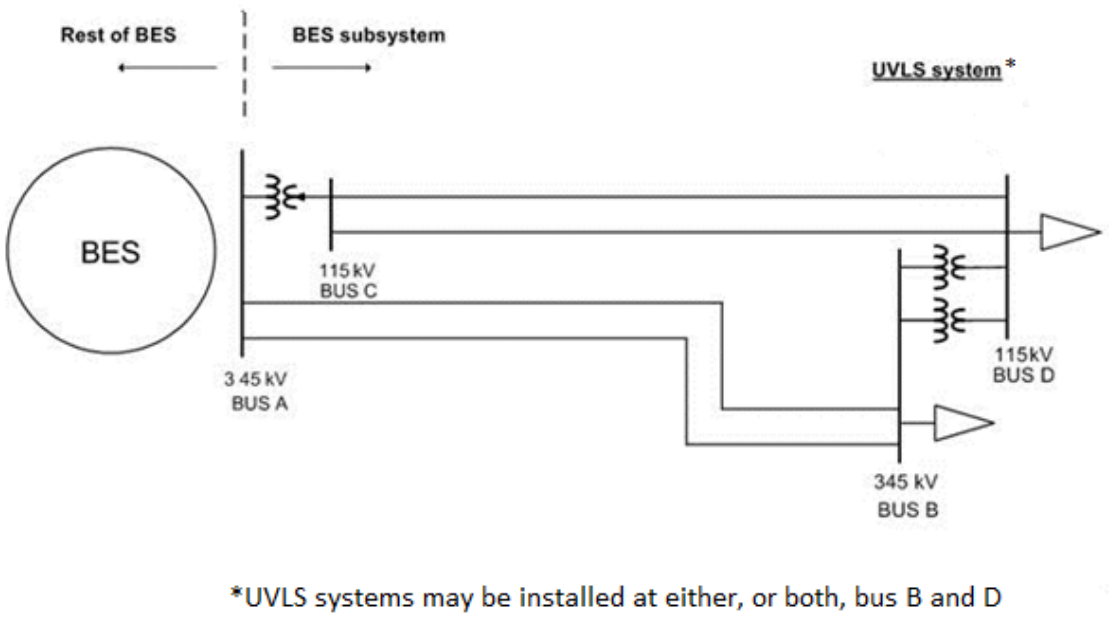


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system

performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[1] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three

[3] Id.

calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well- accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the

directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

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[4] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding).
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] (http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx).
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).
[8] (http://www.nerc.com/docs/docs/ferc/order_693.pdf).
[9] (http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf).

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and

[10] (http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf).
[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[12] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans).

consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and

[13] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning).
[14] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies).
[15] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations).
[16] (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS

threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[19] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis).

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning

[20] Refer to Standards Independent Expert Review Project (IERP). (http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf).
[21] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding).
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators,

and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Exhibit B

Implementation Plans

Implementation Plan for Reliability Standard PRC-004-5

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Implementation Plan

PRC-004-5 – Protection System Misoperation Identification and Correction

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-004-5 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-004-4 – Protection System Misoperation Identification and Correction[1]

Prerequisite Approvals

- PRC-010-2 – Undervoltage Load Shedding

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occurring soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004-5. The standard PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version two of PRC-010 is including undervoltage load shedding (UVLS) that is included in a UVLS Program.

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

[1] PRC-004-4 was adopted by the NERC Board of Trustees on November 13, 2014. PRC-004-4 is pending adoption or approval by applicable governmental authorities. PRC-004-5 will retire PRC-004-3 if PRC-004-4 is not adopted or approved by an applicable governmental authority.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-004-5 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Reliability Standard PRC-010-2

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

PRC-010-2 – Undervoltage Load Shedding

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-010-2 – Undervoltage Load Shedding

Requested Retirements

- PRC-010-1 – Undervoltage Load Shedding[1]

Prerequisite Approvals

- PRC-004-5 — Protection System Misoperation Identification and Correction

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occur soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-010-2. PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version five of PRC-004 is including undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Applicable Entities

- Planning Coordinator
- Transmission Planner
- Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator

Effective Dates

PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

[1] PRC-010-1 was adopted by the NERC Board of Trustees on November 13, 2014.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Exhibit C

Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

In Order No. 672, the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[1] The discussion below identifies these factors and explains how the revisions reflected in proposed Reliability Standards PRC-004-5 and PRC-010-2 (Exhibits A-1 and A-2, respectively) have met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The reliability goals of the proposed Reliability Standards are to ensure that UVLS protective relay Misoperations are identified and corrected, and that UVLS equipment performance is appropriately evaluated. Proposed Reliability Standards PRC-004-5 and PRC-010-2 update the Reliability Standard PRC-004-4 and pending proposed Reliability Standard PRC-010-1, respectively, as Phase 2 of Project 2008-02 entitled Project 2008-02.2, to achieve the specific reliability goal of ensuring that UVLS equipment performance (operation/non-operation) is evaluated and to identify any Misoperation of undervoltage load shedding ("UVLS") equipment. The purpose of proposed Reliability Standard PRC-004-5 is to "[i]dentify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements." The purpose of PRC-010-2 is "[t]o establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs ("UVLS Programs")."

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

The standard drafting team developed the revised, proposed, Reliability Standards under Project 2008-02.2, because during the development of PRC-004-3 (Project 2010-05.1) and PRC-010-1 (Project 2008-02), it was decided that the UVLS standard drafting team would later address the Misoperation of UVLS equipment stemming from the retirement of PRC-022-1 (*Under-Voltage Load Shedding Program Performance*). Phase 1 of Project 2008-02 did not address Misoperation of UVLS equipment due to dependencies on other pending projects. As proposed, (i) Reliability Standard PRC-004-5 revises the Reliability Standard to be applicable to UVLS that is intended to trip one or more BES Elements, and (ii) PRC-010-2 revises Requirement R4 of that Reliability Standard to expressly require evaluation of performance of UVLS Program equipment, with a conforming change to Requirement R5.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standards are each clear and unambiguous as to what is required and who is to comply. The proposed Reliability Standards reflect separate performance elements associated with identifying and correcting Misoperations to address a perceived gap associated with Misoperation of UVLS equipment.

The proposed Reliability Standards apply to the following:

- **Proposed Reliability Standard PRC-004-5:** Applies to Transmission Owners, Generator Owners, and Distribution Providers. It also applies to Protection Systems for BES Elements (with certain enumerated exclusions), underfrequency load shedding ("UFLS") that is intended to trip one or more BES Elements, and (pursuant to the proposed revisions) UVLS that is intended to trip one or more BES Elements.

[3] Order No. 672, at PP 322, 325.

There may be cases where UVLS trips a BES Element, if so, an entity will initiate work under PRC-004. If the entity discovers a Misoperation under PRC-004, the entity will develop and implement a Corrective Action Plan for any known causes of the Misoperation.

- **Proposed Reliability Standard PRC-010-2:** Applies to Planning Coordinators, Transmission Planners, and Undervoltage load shedding (UVLS) entities, which are comprised of Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. The standard drafting team reached consensus that the Planning Coordinator or Transmission Planner is in the best position to assess whether UVLS equipment falls within a UVLS Program. The planners hold the inputs from the UVLS entities and the tools necessary to determine whether specific UVLS operated correctly or failed to operate correctly according to the design of the UVLS Program. When the planner under PRC-010 discovers a potential Misoperation of UVLS equipment, it would be considered a deficiency in the UVLS Program and be addressed accordingly.

For a complete description of the revised language in the Reliability Standards please refer to Section IV. of NERC's Petition, and for a full copy of the Reliability Standards please refer to Exhibit A to NERC's Petition.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

[4] Order No. 672, at P 326.

The Violation Risk Factor ("VRF") and Violation Severity Level ("VSL") for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. The assignment of the severity levels for the VSLs is consistent with the corresponding Requirement and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, and support uniformity and consistency in the determination of similar penalties for similar violations. With regard to the VRF for proposed Reliability Standard PRC-004-5, NERC notes that it is reviewing the VRF for Requirements R1 through R6 consistent with the Commission's directive on May 13, 2015.[5] For these reasons, the proposed Reliability Standards include clear and understandable consequences.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and nonpreferential manner.[6]

The proposed Reliability Standards contain Measures that support the Requirements by clearly identifying what is required and how the Requirements will be measured for compliance. The Measures are listed after each of the Requirements of the proposed PRC-004-5 and PRC-010-2 Reliability Standards and provide clarity on types of evidence to support each Requirement, which will allow the Requirements to be enforced in a consistent and non-preferential manner. The Measures are provided within each of the proposed Reliability Standards in Exhibit A.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[7]

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5 *North American Electric Reliability Corp.*, 151 FERC ¶ 61,129 (2015).
6 Order No. 672 at P 327.
7 Order No. 672, at P 328.

The proposed Reliability Standards PRC-004-5 and PRC-010-2 achieve the reliability goal effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standards employ a process for addressing Misoperation of UVLS equipment which utilizes existing processes and standards, thereby using the most efficient means to address the perceived gap associated with implementation of pending Reliability Standard PRC-010-1 and retirement of currently effective Reliability Standard PRC-022-1. The standard drafting team considered only revising PRC-004-3 during Project 2008-02.2, however, concluded that PRC-004 would initiate a review of UVLS when a BES interrupting device operated but not for cases where a UVLS failed to operate. The standard drafting team determined that the two-pronged approach reflected in NERC's Petition appropriately ensures coverage of UVLS Program equipment. The proposed Reliability Standards work together as a whole, because inclusion of UVLS to the Applicability of PRC-004-5 now addresses the operation of UVLS for BES Elements, and the revisions to PRC-010-2 address operation/non-operation of UVLS equipment within a UVLS Program. PRC-010-2 also includes equipment that trips equipment not classified as BES Elements and that trips BES Elements. Thus, the proposed Reliability Standards provide the necessary Requirements to achieve the stated purpose.

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[8]

The proposed definition and revisions to the Proposed Reliability Standards do not reflect a "lowest common denominator" approach. Pending proposed Reliability Standard PRC-010-1 addresses the Commission's directive in Order No. 693, Paragraph 1509, to require an integrated

[8] Order No. 672, at PP 329-330.

and coordinated approach to all protection systems. In applying this approach to UVLS Programs, the PRC-010-1 would also consolidate existing UVLS related Reliability Standards. The contemplated retirement of PRC-022-1 resulted in a perceived gap associated with Misoperation of UVLS equipment. Project 2008-02.2 and the resulting proposed revisions to Reliability Standards PRC-004-5 and PRC-010-2 thus stem from the response to the Commission's directive in Order No. 693, at Paragraph 1509. Proposed Reliability Standards PRC-004-5 and PRC-010-1 address that perceived gap and represent an improvement to the prior Reliability Standards.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard**.[9]

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability**.[10]

The proposed PRC-004-5 and PRC-010-2 will not cause undue negative effect on competition or result in any unnecessary restrictions

9. **The implementation time for the proposed Reliability Standard is reasonable**.[11]

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[9] Order No. 672, at P 331.

[10] Order No. 672, at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[11] Order No. 672, at P 333.

The proposed effective dates for PRC-004-5 and PRC-010-2 are just and reasonable. NERC proposes an effective date for each proposed Reliability Standard of the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standards are approved. This period will allow time for entities to review current systems and make any necessary adjustments in their internal processes to implement the proposed revision to the pending Reliability Standards. Proposed Reliability Standards PRC-004-5 and PRC-010-2 should take effect contemporaneously as effectiveness of the integrated and coordinated approach to design, evaluation, and reliable operation of UVLS Programs reflected in pending standard PRC-010-1, because such approach includes retirement of PRC-022 and these proposed revisions address Misoperation of UVLS equipment addressed under PRC-022. Aligned action and effectiveness for proposed Reliability Standards PRC-004-5, PRC-010-1, and PRC-010-2, as well as proposed Reliability Standards EOP-011-1 and the pending revisions to the definitions of UVLS Program and Remedial Action Scheme are just and reasonable as the proposals reflect an integrated and coordinated approach for UVLS Programs.[12]

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[13]

The proposed Reliability Standards were developed in accordance with NERC's Commission approved, ANSI- accredited processes for developing and approving Reliability Standards. Exhibit F includes a summary of the standard development proceedings, and details the processes followed to develop the Reliability Standards. These processes included, among other

[12] These listed and pending proposed Reliability Standards and definitional revisions are related. *See*, Section V of the Petition (describing the relationships between these proposals and Reliability Standards and impact on the appropriate Effective Date and implementation).

[13] Order No. 672, at P 334.

things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[14]

NERC has not identified competing public interests regarding the request for approval of the proposed Reliability Standards. No comments were received that indicated the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[15]

No other factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

[14] Order No. 672, at P 335.
[15] Order No. 672, at P 323.

Exhibit D
Mapping Document

Mapping Document
Project 2008-02.2 Phase 2: Undervoltage Load Shedding

During development of PRC-010-1, the standard drafting team provided the following explanation on its approach to cover Misoperation of UVLS equipment in future work:

> "As PRC-022-1 addresses UVLS equipment Misoperations, the UVLS drafting team's intention is for PRC-004 to address Misoperations of UVLS Program equipment. A change to make PRC-004 explicitly applicable to UVLS Program equipment will be addressed once PRC-004-3 – Protection System Misoperation Identification and Correction[1] is completed under Project 2010-05.1 – Misoperations (Phase 1 of Protection Systems)."

The table below demonstrates how proposed changes map from the retirement of PRC-022-1 (retired by the initial 2008-02 project) to the proposed PRC-010-2. The revisions are being proposed to provide additional clarity with the aligning revisions being proposed in PRC-004-5 as shown in Table 2.

[1] PRC-004-3 was surpassed by version four which addressed applicability to dispersed generation resources under Project 2014-01.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	PRC-010-2 proposes Part 4.2 to provide additional clarity that UVLS equipment operations and Misoperations are addressed by Requirement R4 through the Planning Coordinator or Transmission Planner assessment. Part 4.1 was originally embedded in the main Requirement R4 of PRC-010-1 and is now shown as a new Part 4.1 now. Part 4.2 is being proposed to provide the necessary clarity that the assessment conducted following an event that resulted in a voltage excursion for which its UVLS Program was designed to operate must include UVLS Program equipment.	**R4.** Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: **4.1.** whether its UVLS Program resolved the undervoltage issues associated with the event, and **(Proposed) 4.2.** the performance (i.e., operation and non-operation) of the UVLS Program equipment.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
	Part 4.2 requires the Planning Coordinator or Transmission Planner to assess the UVLS equipment performance and address any deficiencies in a Corrective Action Plan (CAP) as required by PRC-010-2, Requirement R5. The clause "in its UVLS Program" was removed to clarify the Corrective Action Plan is addressing components of the assessment, which is about the UVLS Program.	**R5.** Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment.

Table 2: Mapping PRC-022-1 to PRC-004-5		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-5 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	The proposed Applicability 4.2.3 addresses the clause "analyze and document all UVLS operations and Misoperations" in PRC-022-1, Requirement R1. The standard PRC-004-5, Requirement R5 requires a Corrective Action Plan (CAP) to be developed for a known cause of a Misoperation and addresses Requirement R1.5. Requirement R6 requires the implementation of the CAP.	**(Proposed) 4.2.3** Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or

Table 2: Mapping PRC-022-1 to PRC-004-5		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-5 or Comments**
		• Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.

Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

Exhibit E-1
Analysis of Violation Risk Factors and Violation Severity Levels for Proposed Reliability Standard PRC-004-3

NERC
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Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-004-3 – Protection System Misoperation Identification and Correction.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if

violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VRF Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination

[1] *N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,145 (2007) ("VRF Order"), *order on reh'g and compliance filing*, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id.* at fn 15.

- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF Discussion

The discussion below in the tables addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a

revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations and combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1.[3] First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, it must explain this in a declaration why no further corrective actions will be taken.

In the last Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

[3] The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by an owner is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is not in itself likely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R1	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of "High." The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". The performance activity that has been isolated in Requirement R1 of PRC-004-3, to "review" (similar to "analyze"), is consistent with similar requirements in Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement comingles multiple activities
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R1	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R2	
	Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system by creating a gap in analysis.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System component(s) when it determines that (or is unsure whether)its component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the Composite Protection System owned by others. This ensures that all owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R2	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". This requirement and a VRF assignment of Medium is consistent, for example, with Reliability Standards FAC-008-3 – Facility Ratings, R7 ("…shall provide Facility Ratings (for its solely and jointly owned Facilities…"), MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 ("…shall provide appropriate equipment characteristics and system data…"), IRO-015-1 – Special Protection System Data and Documentation, R1.1 ("…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas."), and IRO-016-1 – Coordination of Real-time Activities Between Reliability Coordinators, R1 ("…shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.") which all have a VRF of Medium. Other Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 ("…shall provide documentation…"), PRC-016-0.1 – Special Protection System Misoperations, R3 ("…that owns an SPS shall provide documentation of the misoperation analyses…"), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 ("…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R2	
	Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR

VRF and VSL Justifications – PRC-004-3, R2			
			The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b:		

VRF and VSL Justifications – PRC-004-3, R2	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This Requirement R3, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.

VRF and VSL Justifications – PRC-004-3, R3			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R4	
	An Unidentified cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” This Requirement R4, to perform at least one “investigative action” (similar to “analyze”), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R4	
	A VRF of Medium is not inadvertently lowering the current VRF of High in the former PRC-004-2.1a, Requirements R1 or R3, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R4			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard.		

VRF and VSL Justifications – PRC-004-3, R4	
	This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future Misoperations"), PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…"), FAC-003, R5 ("…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management") all three of which have a VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5			
	An unresolved cause of a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system if the same condition resulted in a future Misoperation.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

VRF and VSL Justifications – PRC-004-3, R5			
The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. This Requirement has a Severe VSL for failure to develop the CAP with the other VSLs being based on tardiness of the development.		

VRF and VSL Justifications – PRC-004-3, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An uncorrected cause of a Misoperation as a result of not implementing a Corrective Action Plan, could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system since the condition could occur again.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2.1a, R1 (TO & DP) and R2 (GO),which both have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future misoperations.") and PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…") which both have a VRF of Medium. The proposed VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justification – PRC-004-3, R6			
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

VRF and VSL Justification – PRC-004-3, R6	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of this Requirement that are not equal in importance and performance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justification – PRC-004-3, R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Exhibit E-2
Analysis of Violation Risk Factors and Violation Severity Levels for Proposed Reliability Standard PRC-010-1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2008-02 Undervoltage Load Shedding (PRC-010-1)

VRF and VSL Justifications

This document provides the Undervoltage Load Shedding Standard Drafting Team's (drafting team's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-010-1 – Undervoltage Load Shedding.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The drafting team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures, or hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or

restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the drafting team considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The drafting team believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-010-1 – Undervoltage Load Shedding is a standard revision with the stated purpose: *To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs.* FERC Order No. 693 requested that PRC-010-0 be modified to require that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency loading shedding (UFLS) and undervoltage load shedding (UVLS) programs. PRC-010-1 addresses this directive in addition to consolidating and revising PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program with three (3) other existing UVLS standards: PRC-020-1 – Under-Voltage Load Shedding Program Database, PRC-021-1 – Under-Voltage Load Shedding Program Data, and PRC-022-1 – Under-Voltage Load Shedding Program Performance.

PRC-010-1 has eight (8) requirements that incorporate and enhance the intent of the requirements of PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The revised standard requires that entities developing an Undervoltage Load Shedding Program (UVLS Program) evaluate the program's effectiveness prior to providing the program specifications and schedule to applicable entities. Applicable entities are then required to adhere to the UVLS Program specifications and implementation schedule, including those specifications and schedules associated with Corrective Action Plans (CAPs) for existing programs. The standard also requires an assessment of a UVLS Program at least once every 60 months, and an assessment to evaluate program performance within 12 months of an applicable event. If program deficiencies are identified as a result of either of these assessments, entities are required to develop and provide a CAP to applicable entities within three (3) months. In addition, there are requirements to update, provide data for, and share a UVLS Program database containing information necessary to model the program for use in event analyses and assessments.

The requirements of PRC-010-1 do not map, one-to-one, with the requirements of the legacy standards. The new requirements comingle various reliability attributes of the legacy standards with new reliability objectives, thus a requirement-to-requirement comparison of VRFs is not always possible. In developing the new VRFs for the requirements of PRC-010-1, the drafting team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding influenced the drafting team's VRF decisions (citing FERC VRF Guideline 3), as the drafting team used PRC-006-1 as a model with respect to PRC-010-1's language and construct.

NERC Criteria - Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications – PRC-010-1 Requirement R1	
Proposed VRF	High
NERC VRF Discussion	PRC-010-1 Requirement R1 meets the NERC criterion for a High VRF. Failure to evaluate a UVLS Program to show that it resolves the undervoltage issue it was designed for, and that it is coordinated with generator voltage ride-through capabilities and other protection and control systems, could lead to implementation of an ineffective or counterproductive program. In addition, failure to subsequently provide the UVLS Program specifications and implementation schedule to applicable entities would negate proper program implementation. Both these implications could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to Bulk Electric System (BES) instability, separation, or Cascading failures.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R1 has parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R1 is similar to EOP-003-2, Requirements R3, R4, and R7, which have approved VRFs of High.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R1 meets the NERC criterion for a High VRF. Failure to evaluate a UVLS Program to show that it resolves the undervoltage issue it was designed for, and that it is coordinated with generator voltage ride-through capabilities and other protection and control systems, could lead to implementation of an ineffective or counterproductive program. In addition, failure to subsequently provide the UVLS Program specifications and implementation schedule to applicable entities would negate proper program implementation. Both these implications could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligations in PRC-010-1 Requirement R1, which are to evaluate the effectiveness of a UVLS Program according to the criteria specified in the two parts and subsequently provide the program specifications and implementation schedule to applicable entities, are all equally critical elements that failure to meet could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or

VRF and VSL Justifications – PRC-010-1 Requirement R1	
	Cascading failures. Therefore, the assigned VRF of High is consistent throughout the requirement.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in parts 1.1 and 1.2.
NERC VSL Guidelines Discussion	The proposed VSL for PRC-010-1 Requirement R1 meets NERC's VSL Guidelines in that there is a binary aspect for failure; the VSL addresses the degrees of compliance with respect to equal importance of the two parts.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** The basis for the current level of compliance in relation to PRC-010-1 Requirement R1 is EOP-003-2 Requirements R3, R4, and R7, as these requirements are being retired because they map to PRC-010-1 Requirement R1. Since the VSL for PRC-010-1 Requirement R1 is binary, the current level of compliance is met or exceeded when compared to the VSLs for EOP-003-2 Requirements R3, R4, and R7.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** The proposed VSL for PRC-010-1 Requirement R1 is binary and is consistent with the guideline in that it is classified as a severe VSL. **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSL for PRC-010-1 Requirement R1 uses the term "effectiveness" from the associated requirement, which could be considered ambiguous terminology; however, Requirement R1 does qualify the term "effectiveness" by indicating that the applicable entity must include what is listed in the requirement's parts in its evaluation of effectiveness. The VSL subsequently notes that the items specified in the parts must be included. This thereby supports uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-010-1 Requirement R1	
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSL for PRC-010-1 Requirement R1 uses similar terminology to that used in the requirement and is therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSL for PRC-010-1 Requirement R1 is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R2	
Proposed VRF	High
NERC VRF Discussion	PRC-010-1 Requirement R2 meets the NERC criterion for a High VRF. Failure to implement a UVLS Program by adhering to the program specifications and implementation schedule increases the risk that the program will not perform properly. Under anticipated Emergency, abnormal, or restorative conditions, this could directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R2 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R2 is similar to PRC-006-1 Requirement R9 and EOP-003-2 Requirement R5, which have approved VRFs of High.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R2 meets the NERC criterion for a High VRF. Failure to implement a UVLS Program by adhering to the program specifications and implementation schedule increases the risk that the program will not perform properly. Under anticipated Emergency, abnormal, or restorative conditions, this could directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligations required in PRC-010-1 Requirement R2 are to adhere to the UVLS Program specifications and implementation schedule associated with program development (per Requirement R1) and corrective action (per Requirement R5). The requirement to develop a CAP in Requirement R5 is assigned a Medium VRF; therefore, execution of the corrective actions required by Requirement R2 has a commensurate VRF of Medium. However, since the obligations related to the development of a UVLS Program in Requirement R1 are assigned a High VRF, the failure to implement the program per Requirement R2 could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures. Therefore, Requirement R2 is assigned a High VRF to reflect the higher risk level associated with the more critical objective.
Proposed Lower VSL	N/A

VRF and VSL Justifications – PRC-010-1 Requirement R2	
Proposed Moderate VSL	N/A
Proposed High VSL	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.
Proposed Severe VSL	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R2 meets NERC's VSL Guidelines in that the VSLs cover aspects of the requirement that are equal in importance.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R2 is a new requirement; therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R2 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R2 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R2 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R3	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R3 meets NERC's criterion for a Medium VRF. Failure to perform a comprehensive assessment to evaluate the effectiveness of a UVLS Program at least once every 60 calendar months could lead to failure to identify and address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly and adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to do a periodic comprehensive assessment of the program, which supplements the annual Transmission Planning (TPL) assessment required by NERC Reliability Standards, would have implications on the BES. Therefore, a violation of Requirement R3 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R3 has parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R3 is consistent with the current requirement it is replacing (PRC-010-0 Requirement R1), which has an approved VRF of Medium. Similar performance exists in PRC-006-1 Requirement R4, which has an approved VRF of High. This discrepancy is justified due to the differing nature of the programs these standards are addressing, as PRC-006-1 addresses mandatory UFLS programs and PRC-010-1 covers optional UVLS Programs. A UFLS program inherently has a more likely overall impact on the BES.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R3 meets NERC's criterion for a Medium VRF. Failure to perform a comprehensive assessment to evaluate the effectiveness of a UVLS Program at least once every 60 calendar months could lead to failure to identify and address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly and

VRF and VSL Justifications – PRC-010-1 Requirement R3	
	adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to do a periodic comprehensive assessment of the program, which supplements the annual TPL assessment required by NERC Reliability Standards, would have implications on the BES. Therefore, a violation of Requirement R3 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligation required in PRC-010-1 Requirement R3 is to periodically evaluate the effectiveness of a UVLS Program according to the criteria specified in the two parts; the parts are equally critical elements that failure to meet could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures. However, violation of these commensurate elements is unlikely to lead to BES instability, separation, or Cascading failures. Therefore, the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in parts 3.1 and 3.2.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R3 meets NERC's VSL Guidelines in that there is a binary aspect for failure; the VSL addresses the degrees of compliance with respect to equal importance of the two parts.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** The proposed VSL for PRC-010-1 Requirement R3 is consistent in nature with the VSL for the requirement it is replacing (PRC-010-0 Requirement R1) and therefore does not lower the current level of compliance.

VRF and VSL Justifications – PRC-010-1 Requirement R3	
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** The proposed VSL for PRC-010-1 Requirement R3 for this binary requirement is consistent with the guideline in that it is classified as a severe VSL. **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSL for PRC-010-1 Requirement R3 does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSL for PRC-010-1 Requirement R3 uses similar terminology to that used in the requirement and is therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSL for PRC-010-1 Requirement R3 is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R4	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R4 meets NERC's criterion for a Medium VRF. Failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event in a timely manner could lead to failure to identify and address a necessary program modification. This could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event would have implications on the BES, as these are infrequent and would be done in addition to the annual TPL assessment required by NERC Reliability Standards. Therefore, a violation of Requirement R4 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R4 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R4 is similar to PRC-022-1 Requirement 1 and PRC-006-1 Requirement R11, which have approved VRFs of Medium.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R4 meets NERC's criterion for a Medium VRF. Failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event in a timely manner could lead to failure to identify and address a necessary program modification. This could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or

VRF and VSL Justifications – PRC-010-1 Requirement R4	
	counterproductive program if the criteria is not met, it is less likely that failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event would have implications on the BES, as these are infrequent and would be done in addition to the annual TPL assessment required by NERC Reliability Standards. Therefore, a violation of Requirement R4 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R4 does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.
Proposed Moderate VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.
Proposed High VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.
Proposed Severe VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R4 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R4 is different in construct from the requirement it is replacing (PRC-022-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.

VRF and VSL Justifications – PRC-010-1 Requirement R4	
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R4 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R4 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R4 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R5 meets NERC's criterion for a Medium VRF. Failure to develop and subsequently provide a CAP to address the deficiencies identified as a result of a UVLS Program assessment in a timely manner could lead to failure to address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, since the development of a CAP in Requirement R5 is dependent on the outcomes of Requirement R3 or R4, the likelihood of implications on the BES is commensurate with those of Requirements R3 and R4, which are assigned Medium VRFs. Therefore, a violation of Requirement R5 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R5 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R5 is similar to PRC-022-1 Requirement R1.5, which has an approved VRF of Medium.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R5 meets NERC's criterion for a Medium VRF. Failure to develop and subsequently provide a CAP to address the deficiencies identified as a result of a UVLS Program assessment in a timely manner could lead to failure to address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, since the development of a CAP in Requirement R5 is dependent on the outcomes of Requirement R3 or R4, the likelihood of implications on the BES is commensurate with those of Requirements R3 and R4, which are assigned Medium VRFs. Therefore, a violation of Requirement R5 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R5 does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.
Proposed Moderate VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.
Proposed High VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.
Proposed Severe VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R5 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R5 is different in construct from the requirement it is replacing (PRC-022-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R5 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R5 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R5 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R6	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R6 meets NERC's criterion for a Lower VRF. Though having a current UVLS Program database is necessary to properly inform accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to annually update a UVLS Program database would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** The requirement has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R6 similar to PRC-006-1 Requirement R6, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R6 meets NERC's criterion for a Lower VRF. Though having a current UVLS Program database is necessary to properly inform accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to annually update a UVLS Program database would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R6 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.
Proposed Moderate VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.
Proposed High VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90

VRF and VSL Justifications – PRC-010-1 Requirement R6	
	calendar days.
Proposed Severe VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R6 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R6 is replacing PRC-020-1 Requirement R1, which is applicable to the Regional Reliability Organization and has no associated VSLs. Therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R6 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R6 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R6 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R7	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R7 meets NERC's criterion for a Lower VRF. Though providing current and formatted data is necessary to properly support a UVLS Program database, which subsequently informs accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to provide the data according to the format and schedule specified would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R7 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3 Consistency among Reliability Standards:** PRC-010-1 Requirement R7 is similar to PRC-006-1 Requirement R8, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R7 meets NERC's criterion for a Lower VRF. Though providing current and formatted data is necessary to properly support a UVLS Program database, which subsequently informs accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to provide the data according to the format and schedule specified would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R7 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR

VRF and VSL Justifications – PRC-010-1 Requirement R7	
	The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.
Proposed Moderate VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.
Proposed High VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.
Proposed Severe VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R7 meets NERC's VSL Guidelines in that the VSLs cover aspects of the requirement that are not equal in importance; there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R7 is different in construct from the requirement it is replacing (PRC-021-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R7 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R7 use similar terminology to that used in the requirement and are therefore consistent with the requirement.

VRF and VSL Justifications – PRC-010-1 Requirement R7	
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R7 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R8	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R8 meets NERC's criterion for a Lower VRF. Though sharing a UVLS Program database with applicable entities in a timely manner supports an integrated and coordinated approach to UVLS programs, this is a planning requirement that is administrative in nature; failure to share the database within 30 calendar days of a request would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** The requirement has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R8 is similar to PRC-006-1 Requirement R7, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R8 meets NERC's criterion for a Lower VRF. Though sharing a UVLS Program database with applicable entities in a timely manner supports an integrated and coordinated approach to UVLS programs, this is a planning requirement that is administrative in nature; failure to share the database within 30 calendar days of a request would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R8 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.
Proposed Moderate VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.

VRF and VSL Justifications – PRC-010-1 Requirement R8	
Proposed High VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.
Proposed Severe VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R8 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R8 is replacing PRC-020-1 Requirement R2, which is applicable to the Regional Reliability Organization and has no associated VSLs. Therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R8 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R8 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R8 are based on a single violation and not cumulative violations.

Exhibit F

Summary of Development History and Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standards PRC-004-5 and PRC-010-2 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit G.

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request ("SAR") for Project 2008-02 Undervoltage Load Shedding (UVLS) was posted for a 30-day informal comment period from January 20, 2010 through February 19, 2010. A revised SAR was posted from September 10, 2013 through October 9, 2013. This SAR was relied upon for development of this Project 2008-02.2.[2]

B. First Posting - Comment Period, Ballot and Non-Binding Poll

Proposed Reliability Standards PRC-004-5 and PRC-010-2 were posted for a 45-day comment period from February 20, 2015 through April 7, 2015, with an initial ballot held from March 27, 2015 through April 7, 2015. Several documents were posted for guidance with the first draft, including the Unofficial Comment Form, Mapping

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

2 NERC, *SC Agenda Package*, at Agenda Item 8, (Feb. 18, 2015), *available at* http://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_021815%20Package_021715_v2.pdf.

Document, and Reliability Standards PRC-004-3 and PRC-010-1 Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") Justification Documents. The initial ballot received 79.93% quorum, and 84.31% approval. The Non-Binding Poll received 79.63% quorum and 88.10% of supportive opinions. There were 49 sets of comments, including comments from approximately 45 different individuals and approximately 40 companies, representing 7 of the 10 industry segments.[3]

C. Final Ballot

Proposed Reliability Standards PRC-004-5 and PRC-010-2 were posted for a 10-final ballot period from April 17, 2015 through April 27, 2015. The proposed Reliability Standards received 84.86% quorum and 89.63% approval.

D. Board of Trustees Adoption

Proposed Reliability Standards PRC-004-5 and PRC-010-2 were adopted by the NERC Board of Trustees on May 7, 2015.

[3] NERC, *Consideration of Comments*, Project 2008-02.2, (April 17, 2015), *available at* http://www.nerc.com/pa/Stand/Prjct200802_2Phs2UndrvltgLdShddngUVLSMsoprtnsDL/ConsiderationofComments_with_Summary_added_2008-02.2_UVLS_05282015.pdf.

Complete Record of Development

Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations

Related Files | 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) | 2010-05.1 Protection System (Misoperations)

Status

Board Adopted: May 7, 2015 - PRC-004-5 and PRC-10-2

Filed with FERC:
US Enforcement Date
Filings and Orders

Background

During the development of PRC-004-3 (Project 2010-05.1) and PRC-010-1 (Project 2008-02), both standard drafting teams decided that the UVLS standard drafting team would address the Misoperation of UVLS Protection Systems due to their work involving PRC-022-1 (*Under-Voltage Load Shedding Program Performance*). The PRC-022-1 Reliability Standard addressed Misoperation of UVLS; however, it is being retired with the creation of PRC-010-1, which was adopted by the NERC Board of Trustees (Board) on November 13, 2014.

This phase of the UVLS project will address Misoperation of UVLS equipment to complete the work anticipated by the two standard drafting teams. The UVLS standard drafting team is currently working to make the necessary standard changes and anticipates submitting proposed changes to NERC Board in May for adoption pending favorable ballot results.

Standard(s) Affected - PRC-004-5 and PRC-010-2

Purpose / Industry Need

A key element for Bulk Electric System (BES) reliability is the correct performance of UVLS Programs that are used in arresting voltage declines and to allow the BES to recover. The identification and correction of any Misoperation of UVLS Protection Systems in a UVLS Program ensures dependable UVLS Program performance.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **PRC-004-5** Clean **(18)** | Redline to Last Posted **(19)** Redline to Last Adopted **(20)** **Implementation Plan** Clean **(21)** | Redline to Last Posted **(22)** **PRC-010-2** Clean **(23)** | Redline to Last Posted **(24)** Redline to Last Adopted **(25)** **Implementation Plan** Clean **(26)** | Redline to Last Posted **(27)**	Final Ballot Info **(32)** Vote	04/17/15 – 04/27/15	Summary **(33)** Ballot Results **(34)**	

Supporting Materials **Mapping Document** Clean **(28)** | Redline to Last Posted **(29)** **PRC-004-3** VRF/VSL Justification **(30)** **PRC-010-1** VRF/VSL Justification **(31)**				
Draft 1 **PRC-004-5** Clean **(1)** | Redline to Last Adopted **(2)** Implementation Plan **(3)** **PRC-010-2** Clean **(4)** | Redline to Last Adopted **(5)** Implementation Plan **(6)** **Supporting Materials** Unofficial Comment Form (Word) **(7)** **Mapping Document** **PRC-004-3** VRF/VSL Justification **(8)** **PRC-010-1** VRF/VSL Justification **(9)** **PRC-004-5** Draft RSAW **PRC-010-2** Draft RSAW	Initial Ballot and Non-Binding Poll Updated Info **(12)** Info **(13)** Vote	03/27/15 - 04/07/15	Summary **(14)** Ballot Results **(15)** Non-binding Poll Results **(16)**	Consideration of Comments **(17)**
	Comment Period Info **(10)** Submit Comments The drafting team did not make substantive changes to PRC-004-5 and PRC-010-2. Therefore, the VRF/VSL Justification documents from the development of PRC-004-3 and PRC-010-1 are posted for reference.	02/20/15 - 04/07/15	Comments Received **(11)**	
	Join Ballot Pool Initially, separate ballot pools were incorrectly created for PRC-004-5 and PRC-010-2. The SBS has been updated with one ballot pool to combine PRC-004-5 and PRC-010-2. If you have already joined the separate ballot	02/20/15 - 3/23/15		

	pools, please register in the combined ballot pool.			
	Send RSAW feedback to: RSAWfeedback@nerc.net	02/20/15 - 04/07/15		

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 12, 2014.
2. NERC Standards Committee authorized initial posting of the standard on February 18, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-004-5 – Protection System Misoperation Identification and Correction for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to the Applicability section to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (*Undervoltage Load Shedding Program Performance*) during the development of PRC-010-1 (*Undervoltage Load Shedding*)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (*Protection System Misoperation Identification and Correction*). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-5

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[2]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None**.**

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[3]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers

[3] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Version	Date	Action	Change Tracking
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5		Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[4] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[5]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[6] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[7]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[4] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[5] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[6] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[7] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** *– A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.
>
> **Example 1d:** A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an “Unnecessary Trip – During Fault” Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay’s characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated

authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[8] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

[8] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.
>
> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a

Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that

certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[9]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an*

[9] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.
>
> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

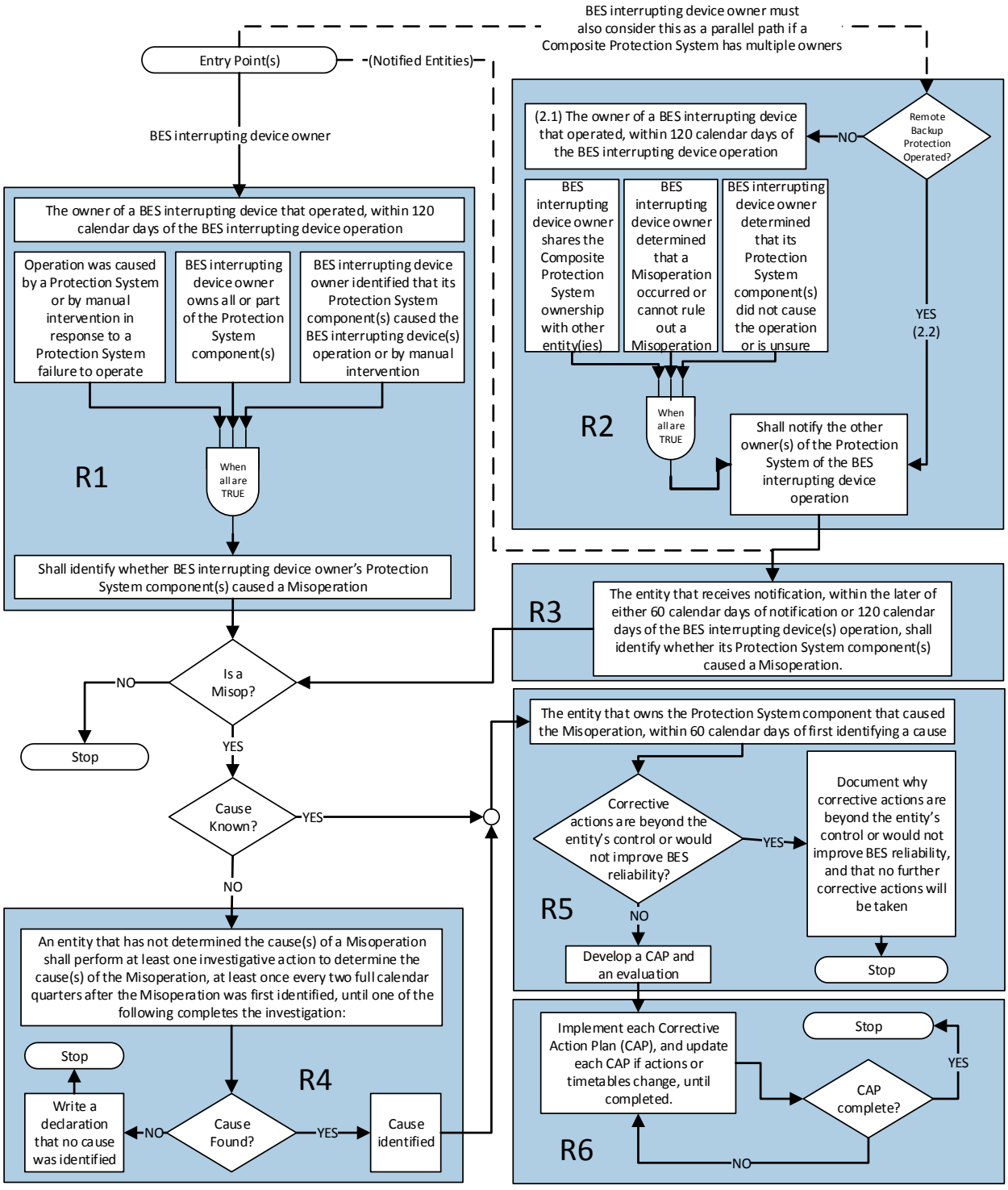
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction

The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

Rationale for Applicability

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 12, 2014.
2. NERC Standards Committee approved initial posting of the standard on February 18, 2015

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-004-5 – Protection System Misoperation Identification and Correction for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to the Applicability section to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (*Undervoltage Load Shedding Program Performance*) during the development of PRC-010-1 (*Undervoltage Load Shedding*)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (*Protection System Misoperation Identification and Correction*). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term "Misoperation" as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-45

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[2]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Dates:Date:** See theProject 2008-02.2 Implementation Plan for this Standard..

5. **Background:**

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).

- ~~Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.~~

~~Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.~~

~~The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.~~

~~Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.~~

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[3]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
~~2~~		~~Modified to address Order No. 693 Directives contained in paragraph 1469.~~	~~Revised~~
~~2~~	~~August 5, 2010~~	~~Adopted by NERC Board of Trustees~~	

[3] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Version	Date	Action	Change Tracking
1a	February 17, 2011	Adopted by NERC Board of Trustees~~Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers~~	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
~~1a~~	~~February 17, 2011~~	~~Adopted by NERC Board of Trustees~~	
1a	September 26, 2011	Appended FERC ~~Order issued approving the~~ approved interpretation of R1 and R3 ~~(FERC's Order is effective as of September 26, 2011)~~to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	~~Errata change: Edited R2 to add "…and generator interconnection Facility…"~~Adopted by NERC Board of Trustees	~~Revision~~Errata change under Project 2010-07 to add "…and generator interconnection Facility…"

Version	Date	Action	Change Tracking
~~2.1a~~	~~February 9, 2012~~	~~Errata change adopted by NERC Board of Trustees~~	
~~2.1a~~	~~September 19, 2013~~	~~FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).~~	
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	~~**Standad i**~~ Applicability ~~revised~~revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources~~. n November 13, 2014 Project 2014-01~~
5		Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[4] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[5]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[6] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[7]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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4 http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

5 "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

6 "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

7 "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** *– A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.
>
> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated

authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[8] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

[8] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.
>
> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a

Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that

certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[9]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an*

[9] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.
>
> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

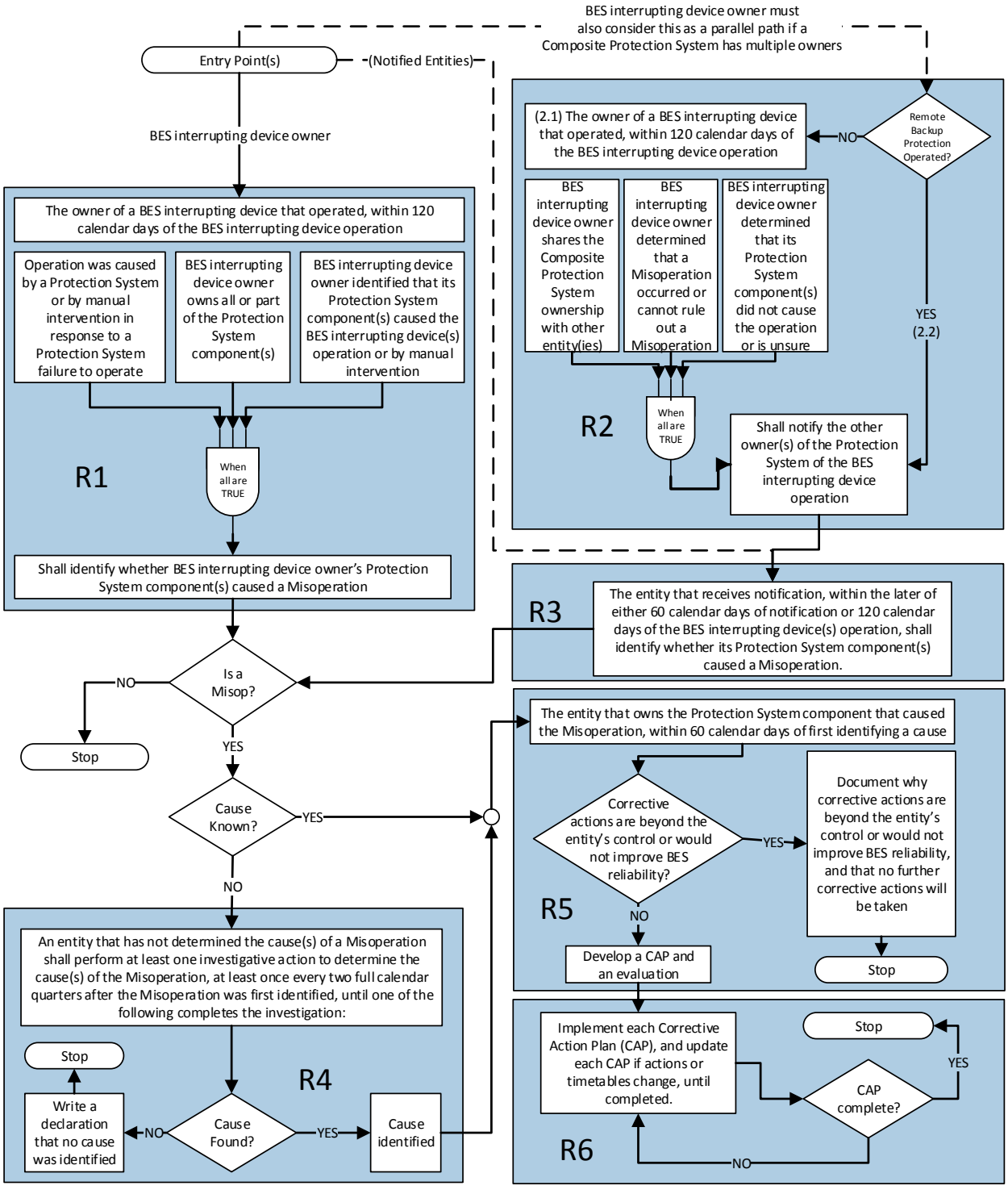
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction:

The only revisions made to this version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

The DGR version of this standard had been labeled PRC-004-4 for balloting purposes. The 'X' had indicated that a version number would be applied at a later time, because multiple versions of PRC-004 were in development at the time of the previous posting. The 'X' designation reflected the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. However, PRC-004-3 was approved by the NERC Board of Trustees on August 14, 2014, so this version has been designated PRC-004-4 to indicate that this version is the successor version.

Rationale for Applicability:

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for "common- mode failure" type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

PRC-004-5 – Protection System Misoperation Identification and Correction

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-004-5 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-004-4 – Protection System Misoperation Identification and Correction[1]

Prerequisite Approvals

- PRC-010-2 – Undervoltage Load Shedding

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occurring soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004. PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version five of PRC-004 is including undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

[1] PRC-004-4 was adopted by the NERC Board of Trustees on November 13, 2014. PRC-004-4 is pending adoption or approval by applicable governmental authorities. PRC-004-5 will retire PRC-004-3 if PRC-004-4 is not adopted or approved by an applicable governmental authority.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-004-5 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees adopted PRC-010-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting on February 18, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-010-2 – Undervoltage Load Shedding for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to Requirements R4 and R5 to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (Undervoltage Load Shedding Program Performance) during the development of PRC-010-1 (Undervoltage Load Shedding)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (Protection System Misoperation Identification and Correction). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment. Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the Glossary of Terms Used in NERC Reliability Standards is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

When this standard receives Board adoption, the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R5 will be removed.

A. Introduction

1. **Title:** Undervoltage Load Shedding
2. **Number:** PRC-010-2
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated

with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

Rationale for Requirement R4: Refer to the Supplemental Section at the end of the document for the rationale.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three

calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For

instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2		Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

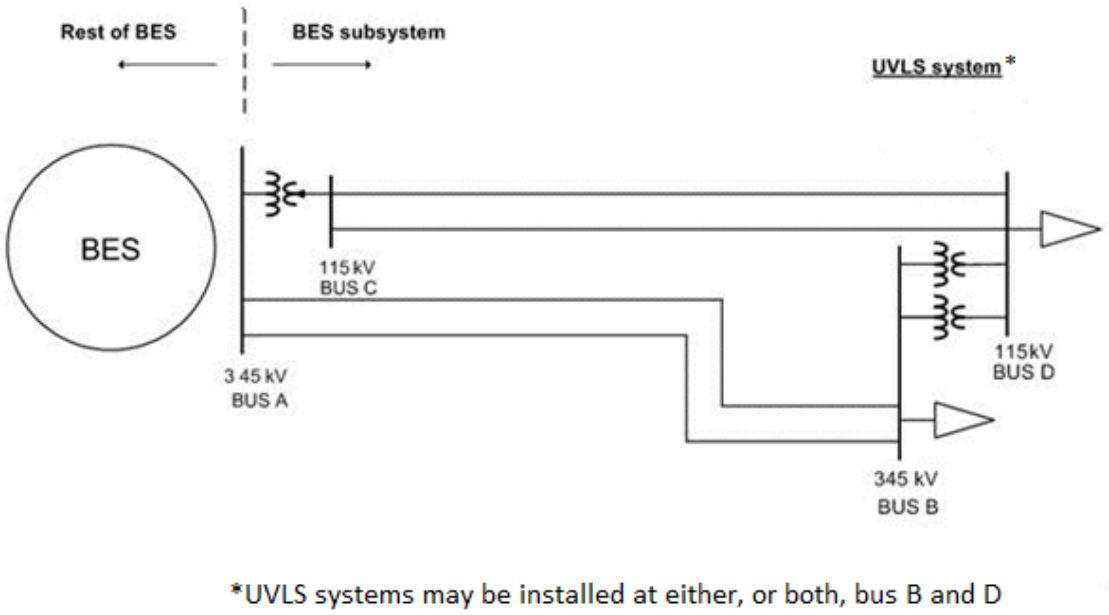


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS

Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[1] of the UVLS relay was caused by a

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5:

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause

[3] Id.

of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The "within three calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators

can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well-accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase “Planning Coordinator or Transmission Planner” provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program’s viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program’s specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for

[4] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding.
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).
[8] http://www.nerc.com/docs/docs/ferc/order_693.pdf.
[9] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.
[10] http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf.

assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2

[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[12] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans.
[13] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning.
[14] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies.

requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition is meant to inherently exclude locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

[15] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations.
[16] http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner,

or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[19] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis.

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

[20] Refer to Standards Independent Expert Review Project (IERP). http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf.
[21] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding.
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees adopted PRC-010-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting on February 18, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-010-2 – Undervoltage Load Shedding for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to Requirements R4 and R5 to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (Undervoltage Load Shedding Program Performance) during the development of PRC-010-1 (Undervoltage Load Shedding)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (Protection System Misoperation Identification and Correction). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment. Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the Glossary of Terms Used in NERC Reliability Standards is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

When this standard receives Board adoption, the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R5 will be removed.

A. Introduction

1. **Title:** Undervoltage Load Shedding

2. **Number:** PRC-010-~~1~~-2

3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

~~1. Background:~~

~~PRC-010-1 – Undervoltage Load Shedding is a consolidation and revision of the following Reliability Standards:~~

- ~~PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program~~
- ~~PRC-020-1 – Under-Voltage Load Shedding Program Database~~
- ~~PRC-021-1 – Under-Voltage Load Shedding Program Data~~
- ~~PRC-022-1 – Under-Voltage Load Shedding Program Performance~~

~~The UVLS Standard Drafting Team (or drafting team) developed the revised PRC-010-1 to meet the following objectives:~~

- ~~Address the FERC directive in Order No. 693, Paragraph 1509 to modify PRC-010-0 to require an integrated and coordinated approach to all protection systems.~~
- ~~Replace the applicability to and involvement of the Regional Reliability Organization (RRO) in PRC-020-1 and PRC-021-1.~~
- ~~Consolidate the UVLS-related standards into one comprehensive standard (similar to the construct of FERC-approved PRC-006-1 – Automatic~~

~~Underfrequency Load Shedding).~~

- ~~Clearly identify and separate centrally controlled undervoltage□based load shedding due to the reliability requirements needed for this type of load shedding as compared to other UVLS systems.~~
- ~~Create a single results□based standard that addresses current reliability issues associated with UVLS.~~

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including,

but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

Rationale for Requirement R4: Refer to the Supplemental Section at the end of the document for the rationale.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate ~~whether its UVLS Program resolved the undervoltage issues associated with the event.~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies ~~in its UVLS Program~~ during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2		Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

~~PRC-010-1 is a single, comprehensive standard that addresses the same reliability principles outlined in its legacy standards, PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The standard also addresses a FERC directive from Order No. 693, Paragraph 1509. This paragraph directs NERC to develop a modification to PRC-010-0 that requires an integrated and coordinated approach to all protection systems, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency load shedding (UFLS) and UVLS programs.~~

~~Since FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding was developed under a similar construct of combining existing standards and addressing a FERC Order No. 693 directive, the drafting team looked to this standard as a guide. With the understanding that UVLS and UFLS systems have fundamental differences, the drafting team adopted PRC-006-1's industry-vetted reliability principles and language as applicable to UVLS Programs.~~

~~The drafting team's established purpose for PRC-010-1 is to clearly define the responsibilities of applicable entities to pursue an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS Programs. Since the need for and design of UVLS Programs is unique to each system preservation footprint, the intent of the standard is to provide a framework of reliability requirements for such programs to which each individual entity can apply its program's specific considerations and characteristics. The drafting team emphasizes that PRC-010-1 does not require a mandatory UVLS Program, nor does this standard address the need to have a UVLS Program. PRC-010-1 applies only after an entity has determined the need for a UVLS Program as a result of its own planning studies.~~

~~The~~The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

~~The design and characteristics of a centrally controlled undervoltage-based load shedding system are commensurate with a Special Protection System (SPS) or Remedial Action Scheme (RAS), therefore, the drafting team maintains that this type of load shedding should be covered by SPS or RAS-related Reliability Standards. Therefore, PRC-010-1 introduces a new Glossary of Terms Used in NERC Reliability Standards term, UVLS Program, to establish the applicability of PRC-010-1 to automatic load shedding programs consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Undervoltage-based load shedding that does not have such an impact as determined by the Planning Coordinator or Transmission Planner is not included. It is further noted that this term excludes centrally controlled undervoltage-based load shedding.~~

~~Subsequently, since the current Glossary of Terms Used in NERC Reliability Standards definition of Special Protection System excludes UVLS, concurrent Project 2010□05.2 – Special Protection Systems (Phase 2 of Protection Systems) will adjust the definition to exclude only UVLS Programs as defined above and therefore include centrally controlled undervoltage□based load shedding. Of note, the drafting team for Project 2010□05.2 is proposing to change the term from Special Protection System to Remedial Action Scheme. Accordingly, PRC□010□1 uses the term Remedial Action Scheme instead of Special Protection System. In the current inventory of NERC Reliability Standards, there is one instance of the term undervoltage load shedding program, which is in NUC□001□2.1. Project 2012□13 Nuclear Plant Interface Coordination has adjusted the language of this reference in proposed NUC□001□3 to eliminate any potential confusion of a lowercase usage of a defined term. Likewise, future projects containing standards that feature variations of the term (e.g., undervoltage load shedding system) will also be advised to consider the newly defined term.~~

~~Requirements of the revised Reliability Standard PRC□010□1 meet the following objectives:~~

- ~~Evaluate a UVLS Program's effectiveness prior to implementation, including the program's coordination with other protection systems and generator voltage ride-through capabilities.~~
- ~~Adhere to UVLS Program specifications and implementation schedule.~~
- ~~Perform periodic assessment and performance analysis of UVLS Programs and resolve identified deficiencies.~~
- ~~Maintain and share UVLS Program data.~~

~~Also of note, Project 2009□03 – Emergency Operations is proposing EOP□011□1, which, as part of the overall revisions, retires specific requirements from EOP□003□2 – Load Shedding Plans to eliminate identified redundancy between PRC□010□1 and EOP□003□2. In addition, the UVLS drafting team's intention is for PRC□004 to address Misoperations of UVLS Programs that are intended to trip one or more BES Elements. A change to make these types of UVLS Programs explicitly applicable to PRC□004 will be addressed once PRC□004□3 – Protection System Misoperation Identification and Correction is completed under Project 2010□05.1 – Misoperations (Phase 1 of Protection Systems).~~

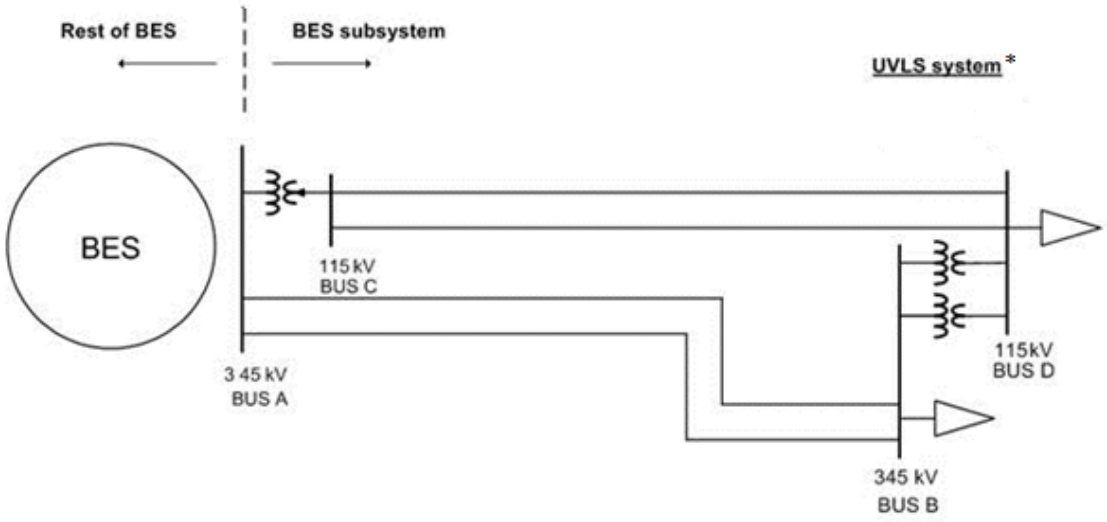
Guidelines for UVLS Program Definition

The definition for the term~~-~~, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The ~~definition for the term~~ UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS~~,~~), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard ~~is to~~includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the ~~BES.~~Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

~~Below~~Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between ~~bus~~buses A and ~~bus~~ B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading ~~involving the BES.~~, a UVLS system (installed at either, or both, bus B and D) used to mitigate this ~~case~~Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system ~~would be~~is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.



*UVLS systems may be installed at either, or both, bus B and D

~~High Level Requirement Overview~~

~~Requirement~~

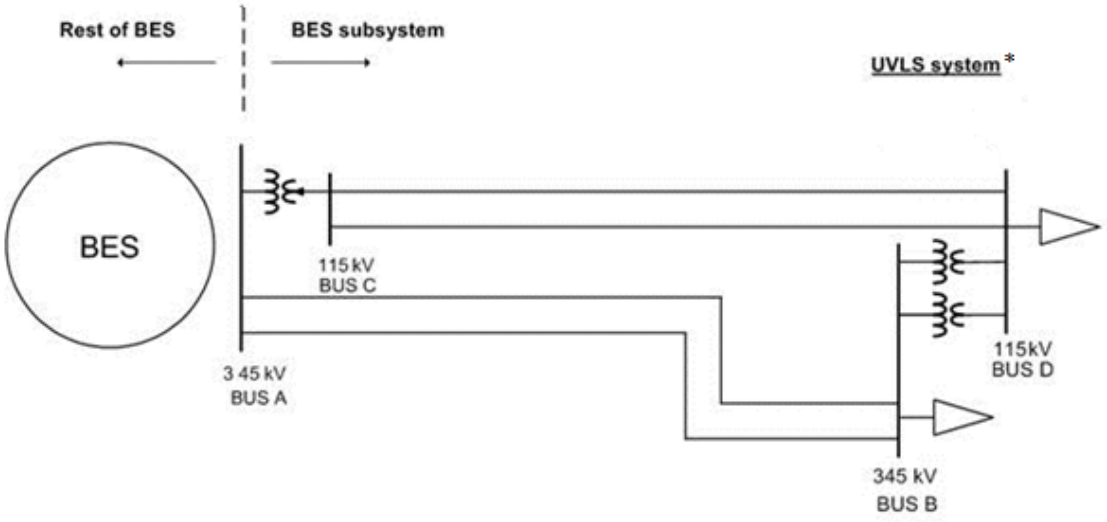


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1~~:~~

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static ~~var~~voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

~~Examples~~The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2~~:~~

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed~~, etc~~. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

> **CAP Example 1** - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the ~~misoperation~~Misoperation[1] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3~~:~~

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment ~~should~~is required to be completed at least once every 60 calendar months to capture the accumulated

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment supplementscomplements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

With respect to situations in which a material change to system and topology or operating conditions would necessitate a comprehensive assessment of the UVLS Program, it is understood that the term material change is not transportable on a continent□wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4:

TheAfter a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues for an event that occurred on the system. It is expected that, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event shall beis performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.
[3] Id.

effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12- calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC- 006-1.

Guidelines for Requirement R5:

Requirement R5 promotes the prudent correction of an identified problem during the assessment ~~evaluations~~ of ~~each~~a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate~~.~~
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated~~.~~

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, ~~the drafting team believes that within~~ three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three calendar months” time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP’s associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop ~~remedial action plans~~Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted

- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS~~,~~), and RAS~~.~~

Additionally, the UVLS Program database ~~should~~is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well-accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~

0	February 8, 2005	Adopted by NERC Board of Trustees	
0	March 16, 2007	Approved by FERC	
0	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
1.0	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Completed revision, merged and updated PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program

according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment ~~of a UVLS Program~~ performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. -Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

[4] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding.
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project 2010-05_Protection_System_Misoperations.aspx).
[8] http://www.nerc.com/docs/docs/ferc/order_693.pdf.
[9] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by

[10] http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf.
[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[12] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans.

Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition is meant to inherently exclude locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

[13] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning.
[14] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies.
[15] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations.
[16] http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion)

to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

[19] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis.
[20] Refer to Standards Independent Expert Review Project (IERP). http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf.
[21] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding.
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

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Implementation Plan

PRC-010-2 – Undervoltage Load Shedding

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-010-2 – Undervoltage Load Shedding

Requested Retirements

- PRC-010-1 – Undervoltage Load Shedding[1]

Prerequisite Approvals

- PRC-004-5 — Protection System Misoperation Identification and Correction

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occur soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004. PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version five of PRC-004 is including undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Applicable Entities

- Planning Coordinator
- Transmission Planner
- Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator

[1] PRC-010-1 was adopted by the NERC Board of Trustees on November 13, 2014.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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Unofficial Comment Form

Project 2008-02.2 Phase 2 UVLS: Misoperations

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the standards. The formal comment period is **open through 8 p.m. Tuesday, April 7, 2015**.

If you have questions, contact Scott Barfield-McGinnis, Standards Developer at scott.barfield@nerc.net or by telephone at 404-446-9689.

Project 2008-02.2 – Phase 2 Undervoltage Load Shedding: Misoperations

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (*Undervoltage Load Shedding Program Performance*) during the development of PRC-010-1 (*Undervoltage Load Shedding*)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (*Protection System Misoperation Identification and Correction*). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication

to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term "Misoperation" as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

Question

1. Do you agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2? If not, please provide comments and suggestions to improve clarity.

   ☐ Yes
   ☐ No

   Comments:

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Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-004-3 – Protection System Misoperation Identification and Correction.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if

violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VRF Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination

[1] *N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,145 (2007) ("VRF Order"), *order on reh'g and compliance filing*, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id.* at fn 15.

- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF Discussion

The discussion below in the tables addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a

revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations and combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1.[3] First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, it must explain this in a declaration why no further corrective actions will be taken.

In the last Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

[3] The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by an owner is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is not in itself likely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R1	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of "High." The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". The performance activity that has been isolated in Requirement R1 of PRC-004-3, to "review" (similar to "analyze"), is consistent with similar requirements in Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement comingles multiple activities
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R1	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R2	
	Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system by creating a gap in analysis.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System component(s) when it determines that (or is unsure whether)its component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the Composite Protection System owned by others. This ensures that all owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R2	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". This requirement and a VRF assignment of Medium is consistent, for example, with Reliability Standards FAC-008-3 – Facility Ratings, R7 ("…shall provide Facility Ratings (for its solely and jointly owned Facilities…"), MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 ("…shall provide appropriate equipment characteristics and system data…"), IRO-015-1 – Special Protection System Data and Documentation, R1.1 ("…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas."), and IRO-016-1 – Coordination of Real-time Activities Between Reliability Coordinators, R1 ("…shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.") which all have a VRF of Medium. Other Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 ("…shall provide documentation…"), PRC-016-0.1 – Special Protection System Misoperations, R3 ("…that owns an SPS shall provide documentation of the misoperation analyses…"), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 ("…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R2			
	Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR

VRF and VSL Justifications – PRC-004-3, R2			
			The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b:		

VRF and VSL Justifications – PRC-004-3, R2	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This Requirement R3, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.

VRF and VSL Justifications – PRC-004-3, R3			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R4	
	An Unidentified cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." This Requirement R4, to perform at least one "investigative action" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R4	
	A VRF of Medium is not inadvertently lowering the current VRF of High in the former PRC-004-2.1a, Requirements R1 or R3, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R4			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard.		

VRF and VSL Justifications – PRC-004-3, R4	
	This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future Misoperations"), PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…"), FAC-003, R5 ("…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management") all three of which have a VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5			
	An unresolved cause of a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system if the same condition resulted in a future Misoperation.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

VRF and VSL Justifications – PRC-004-3, R5			
The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. This Requirement has a Severe VSL for failure to develop the CAP with the other VSLs being based on tardiness of the development.		

VRF and VSL Justifications – PRC-004-3, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An uncorrected cause of a Misoperation as a result of not implementing a Corrective Action Plan, could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system since the condition could occur again.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2.1a, R1 (TO & DP) and R2 (GO),which both have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan”. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future misoperations.”) and PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”) which both have a VRF of Medium. The proposed VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

VRF and VSL Justification – PRC-004-3, R6	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of this Requirement that are not equal in importance and performance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justification – PRC-004-3, R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	PRC-010-2 proposes Part 4.2 to provide additional clarity that UVLS equipment operations and Misoperations are addressed by Requirement R4 through the Planning Coordinator or Transmission Planner assessment. Part 4.1 was originally embedded in the main Requirement R4 of PRC-010-1 and is now shown as a new Part 4.1 now. Part 4.2 is being proposed to provide the necessary clarity that the assessment conducted following an event that resulted in a voltage excursion for which its UVLS Program was designed to operate must include UVLS Program equipment.	**R4.** Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: **4.1.** whether its UVLS Program resolved the undervoltage issues associated with the event, and **(Proposed) 4.2.** the performance (i.e., operation and non-operation) of the UVLS Program equipment.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
	Part 4.2 requires the Planning Coordinator or Transmission Planner to assess the UVLS equipment performance and address any deficiencies in a Corrective Action Plan (CAP) as required by PRC-010-2, Requirement R5. The clause "in its UVLS Program" was removed to clarify the Corrective Action Plan is addressing components of the assessment, which is about the UVLS Program.	**R5.** Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Table 2: Mapping PRC-004-5		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-5 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	Applicability 4.2.3 addresses the clause "analyze and document all UVLS operations and Misoperations."	**4.2.3** Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2008-02 Undervoltage Load Shedding (PRC-010-1)

VRF and VSL Justifications

This document provides the Undervoltage Load Shedding Standard Drafting Team's (drafting team's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-010-1 – Undervoltage Load Shedding.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The drafting team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures, or hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or

restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the drafting team considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The drafting team believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-010-1 – Undervoltage Load Shedding is a standard revision with the stated purpose: *To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs.* FERC Order No. 693 requested that PRC-010-0 be modified to require that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency loading shedding (UFLS) and undervoltage load shedding (UVLS) programs. PRC-010-1 addresses this directive in addition to consolidating and revising PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program with three (3) other existing UVLS standards: PRC-020-1 – Under-Voltage Load Shedding Program Database, PRC-021-1 – Under-Voltage Load Shedding Program Data, and PRC-022-1 – Under-Voltage Load Shedding Program Performance.

PRC-010-1 has eight (8) requirements that incorporate and enhance the intent of the requirements of PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The revised standard requires that entities developing an Undervoltage Load Shedding Program (UVLS Program) evaluate the program's effectiveness prior to providing the program specifications and schedule to applicable entities. Applicable entities are then required to adhere to the UVLS Program specifications and implementation schedule, including those specifications and schedules associated with Corrective Action Plans (CAPs) for existing programs. The standard also requires an assessment of a UVLS Program at least once every 60 months, and an assessment to evaluate program performance within 12 months of an applicable event. If program deficiencies are identified as a result of either of these assessments, entities are required to develop and provide a CAP to applicable entities within three (3) months. In addition, there are requirements to update, provide data for, and share a UVLS Program database containing information necessary to model the program for use in event analyses and assessments.

The requirements of PRC-010-1 do not map, one-to-one, with the requirements of the legacy standards. The new requirements comingle various reliability attributes of the legacy standards with new reliability objectives, thus a requirement-to-requirement comparison of VRFs is not always possible. In developing the new VRFs for the requirements of PRC-010-1, the drafting team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding influenced the drafting team's VRF decisions (citing FERC VRF Guideline 3), as the drafting team used PRC-006-1 as a model with respect to PRC-010-1's language and construct.

NERC Criteria - Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications – PRC-010-1 Requirement R1	
Proposed VRF	High
NERC VRF Discussion	PRC-010-1 Requirement R1 meets the NERC criterion for a High VRF. Failure to evaluate a UVLS Program to show that it resolves the undervoltage issue it was designed for, and that it is coordinated with generator voltage ride-through capabilities and other protection and control systems, could lead to implementation of an ineffective or counterproductive program. In addition, failure to subsequently provide the UVLS Program specifications and implementation schedule to applicable entities would negate proper program implementation. Both these implications could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to Bulk Electric System (BES) instability, separation, or Cascading failures.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R1 has parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R1 is similar to EOP-003-2, Requirements R3, R4, and R7, which have approved VRFs of High.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R1 meets the NERC criterion for a High VRF. Failure to evaluate a UVLS Program to show that it resolves the undervoltage issue it was designed for, and that it is coordinated with generator voltage ride-through capabilities and other protection and control systems, could lead to implementation of an ineffective or counterproductive program. In addition, failure to subsequently provide the UVLS Program specifications and implementation schedule to applicable entities would negate proper program implementation. Both these implications could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligations in PRC-010-1 Requirement R1, which are to evaluate the effectiveness of a UVLS Program according to the criteria specified in the two parts and subsequently provide the program specifications and implementation schedule to applicable entities, are all equally critical elements that failure to meet could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or

VRF and VSL Justifications – PRC-010-1 Requirement R1	
	Cascading failures. Therefore, the assigned VRF of High is consistent throughout the requirement.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in parts 1.1 and 1.2.
NERC VSL Guidelines Discussion	The proposed VSL for PRC-010-1 Requirement R1 meets NERC's VSL Guidelines in that there is a binary aspect for failure; the VSL addresses the degrees of compliance with respect to equal importance of the two parts.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** The basis for the current level of compliance in relation to PRC-010-1 Requirement R1 is EOP-003-2 Requirements R3, R4, and R7, as these requirements are being retired because they map to PRC-010-1 Requirement R1. Since the VSL for PRC-010-1 Requirement R1 is binary, the current level of compliance is met or exceeded when compared to the VSLs for EOP-003-2 Requirements R3, R4, and R7.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** The proposed VSL for PRC-010-1 Requirement R1 is binary and is consistent with the guideline in that it is classified as a severe VSL. **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSL for PRC-010-1 Requirement R1 uses the term "effectiveness" from the associated requirement, which could be considered ambiguous terminology; however, Requirement R1 does qualify the term "effectiveness" by indicating that the applicable entity must include what is listed in the requirement's parts in its evaluation of effectiveness. The VSL subsequently notes that the items specified in the parts must be included. This thereby supports uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-010-1 Requirement R1	
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSL for PRC-010-1 Requirement R1 uses similar terminology to that used in the requirement and is therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSL for PRC-010-1 Requirement R1 is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R2	
Proposed VRF	High
NERC VRF Discussion	PRC-010-1 Requirement R2 meets the NERC criterion for a High VRF. Failure to implement a UVLS Program by adhering to the program specifications and implementation schedule increases the risk that the program will not perform properly. Under anticipated Emergency, abnormal, or restorative conditions, this could directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R2 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R2 is similar to PRC-006-1 Requirement R9 and EOP-003-2 Requirement R5, which have approved VRFs of High.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R2 meets the NERC criterion for a High VRF. Failure to implement a UVLS Program by adhering to the program specifications and implementation schedule increases the risk that the program will not perform properly. Under anticipated Emergency, abnormal, or restorative conditions, this could directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligations required in PRC-010-1 Requirement R2 are to adhere to the UVLS Program specifications and implementation schedule associated with program development (per Requirement R1) and corrective action (per Requirement R5). The requirement to develop a CAP in Requirement R5 is assigned a Medium VRF; therefore, execution of the corrective actions required by Requirement R2 has a commensurate VRF of Medium. However, since the obligations related to the development of a UVLS Program in Requirement R1 are assigned a High VRF, the failure to implement the program per Requirement R2 could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures. Therefore, Requirement R2 is assigned a High VRF to reflect the higher risk level associated with the more critical objective.
Proposed Lower VSL	N/A

VRF and VSL Justifications – PRC-010-1 Requirement R2	
Proposed Moderate VSL	N/A
Proposed High VSL	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.
Proposed Severe VSL	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R2 meets NERC's VSL Guidelines in that the VSLs cover aspects of the requirement that are equal in importance.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R2 is a new requirement; therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R2 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R2 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R2 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R3	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R3 meets NERC's criterion for a Medium VRF. Failure to perform a comprehensive assessment to evaluate the effectiveness of a UVLS Program at least once every 60 calendar months could lead to failure to identify and address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly and adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to do a periodic comprehensive assessment of the program, which supplements the annual Transmission Planning (TPL) assessment required by NERC Reliability Standards, would have implications on the BES. Therefore, a violation of Requirement R3 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R3 has parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R3 is consistent with the current requirement it is replacing (PRC-010-0 Requirement R1), which has an approved VRF of Medium. Similar performance exists in PRC-006-1 Requirement R4, which has an approved VRF of High. This discrepancy is justified due to the differing nature of the programs these standards are addressing, as PRC-006-1 addresses mandatory UFLS programs and PRC-010-1 covers optional UVLS Programs. A UFLS program inherently has a more likely overall impact on the BES.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R3 meets NERC's criterion for a Medium VRF. Failure to perform a comprehensive assessment to evaluate the effectiveness of a UVLS Program at least once every 60 calendar months could lead to failure to identify and address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly and

VRF and VSL Justifications – PRC-010-1 Requirement R3	
	adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to do a periodic comprehensive assessment of the program, which supplements the annual TPL assessment required by NERC Reliability Standards, would have implications on the BES. Therefore, a violation of Requirement R3 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligation required in PRC-010-1 Requirement R3 is to periodically evaluate the effectiveness of a UVLS Program according to the criteria specified in the two parts; the parts are equally critical elements that failure to meet could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures. However, violation of these commensurate elements is unlikely to lead to BES instability, separation, or Cascading failures. Therefore, the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in parts 3.1 and 3.2.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R3 meets NERC's VSL Guidelines in that there is a binary aspect for failure; the VSL addresses the degrees of compliance with respect to equal importance of the two parts.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** The proposed VSL for PRC-010-1 Requirement R3 is consistent in nature with the VSL for the requirement it is replacing (PRC-010-0 Requirement R1) and therefore does not lower the current level of compliance.

VRF and VSL Justifications – PRC-010-1 Requirement R3	
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** The proposed VSL for PRC-010-1 Requirement R3 for this binary requirement is consistent with the guideline in that it is classified as a severe VSL. **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSL for PRC-010-1 Requirement R3 does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSL for PRC-010-1 Requirement R3 uses similar terminology to that used in the requirement and is therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSL for PRC-010-1 Requirement R3 is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R4	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R4 meets NERC's criterion for a Medium VRF. Failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event in a timely manner could lead to failure to identify and address a necessary program modification. This could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event would have implications on the BES, as these are infrequent and would be done in addition to the annual TPL assessment required by NERC Reliability Standards. Therefore, a violation of Requirement R4 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R4 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R4 is similar to PRC-022-1 Requirement 1 and PRC-006-1 Requirement R11, which have approved VRFs of Medium.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R4 meets NERC's criterion for a Medium VRF. Failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event in a timely manner could lead to failure to identify and address a necessary program modification. This could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or

VRF and VSL Justifications – PRC-010-1 Requirement R4	
	counterproductive program if the criteria is not met, it is less likely that failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event would have implications on the BES, as these are infrequent and would be done in addition to the annual TPL assessment required by NERC Reliability Standards. Therefore, a violation of Requirement R4 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R4 does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.
Proposed Moderate VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.
Proposed High VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.
Proposed Severe VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R4 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R4 is different in construct from the requirement it is replacing (PRC-022-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.

VRF and VSL Justifications – PRC-010-1 Requirement R4	
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R4 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R4 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R4 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R5 meets NERC's criterion for a Medium VRF. Failure to develop and subsequently provide a CAP to address the deficiencies identified as a result of a UVLS Program assessment in a timely manner could lead to failure to address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, since the development of a CAP in Requirement R5 is dependent on the outcomes of Requirement R3 or R4, the likelihood of implications on the BES is commensurate with those of Requirements R3 and R4, which are assigned Medium VRFs. Therefore, a violation of Requirement R5 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R5 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R5 is similar to PRC-022-1 Requirement R1.5, which has an approved VRF of Medium.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R5 meets NERC's criterion for a Medium VRF. Failure to develop and subsequently provide a CAP to address the deficiencies identified as a result of a UVLS Program assessment in a timely manner could lead to failure to address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, since the development of a CAP in Requirement R5 is dependent on the outcomes of Requirement R3 or R4, the likelihood of implications on the BES is commensurate with those of Requirements R3 and R4, which are assigned Medium VRFs. Therefore, a violation of Requirement R5 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R5 does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.
Proposed Moderate VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.
Proposed High VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.
Proposed Severe VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R5 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R5 is different in construct from the requirement it is replacing (PRC-022-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R5 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R5 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R5 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R6	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R6 meets NERC's criterion for a Lower VRF. Though having a current UVLS Program database is necessary to properly inform accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to annually update a UVLS Program database would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** The requirement has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R6 similar to PRC-006-1 Requirement R6, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R6 meets NERC's criterion for a Lower VRF. Though having a current UVLS Program database is necessary to properly inform accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to annually update a UVLS Program database would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R6 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.
Proposed Moderate VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.
Proposed High VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90

VRF and VSL Justifications – PRC-010-1 Requirement R6	
	calendar days.
Proposed Severe VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R6 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R6 is replacing PRC-020-1 Requirement R1, which is applicable to the Regional Reliability Organization and has no associated VSLs. Therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R6 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R6 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R6 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R7	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R7 meets NERC's criterion for a Lower VRF. Though providing current and formatted data is necessary to properly support a UVLS Program database, which subsequently informs accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to provide the data according to the format and schedule specified would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R7 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3 Consistency among Reliability Standards:** PRC-010-1 Requirement R7 is similar to PRC-006-1 Requirement R8, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R7 meets NERC's criterion for a Lower VRF. Though providing current and formatted data is necessary to properly support a UVLS Program database, which subsequently informs accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to provide the data according to the format and schedule specified would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R7 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR

VRF and VSL Justifications – PRC-010-1 Requirement R7	
	The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.
Proposed Moderate VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.
Proposed High VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.
Proposed Severe VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R7 meets NERC's VSL Guidelines in that the VSLs cover aspects of the requirement that are not equal in importance; there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R7 is different in construct from the requirement it is replacing (PRC-021-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R7 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R7 use similar terminology to that used in the requirement and are therefore consistent with the requirement.

VRF and VSL Justifications – PRC-010-1 Requirement R7	
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R7 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R8	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R8 meets NERC's criterion for a Lower VRF. Though sharing a UVLS Program database with applicable entities in a timely manner supports an integrated and coordinated approach to UVLS programs, this is a planning requirement that is administrative in nature; failure to share the database within 30 calendar days of a request would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** The requirement has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R8 is similar to PRC-006-1 Requirement R7, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R8 meets NERC's criterion for a Lower VRF. Though sharing a UVLS Program database with applicable entities in a timely manner supports an integrated and coordinated approach to UVLS programs, this is a planning requirement that is administrative in nature; failure to share the database within 30 calendar days of a request would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R8 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.
Proposed Moderate VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.

VRF and VSL Justifications – PRC-010-1 Requirement R8	
Proposed High VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.
Proposed Severe VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R8 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R8 is replacing PRC-020-1 Requirement R2, which is applicable to the Regional Reliability Organization and has no associated VSLs. Therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R8 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R8 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R8 are based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2008-02.2 Phase 2 Undervoltage Load Shedding (UVLS): Misoperations

Formal Comment Period Now Open through April 7, 2015
Ballot Pool Forming Now through March 23, 2015

Balloting and commenting for this project are in the Standards Balloting & Commenting System (SBS)

Now Available

A 45-day formal comment period for **PRC-004-5 – Protection System Misoperation Identification and Correction and PRC-010-2 – Under Voltage Load Shedding** is open through **8 p.m. Eastern on Tuesday, April 7, 2015.**

Standards Balloting and Commenting System (SBS) Login, Registration, Validation and Permissions

To **comment** in the SBS, you must have a contributor, voter, or proxy role.
To **join a ballot pool and vote** in the SBS, you must have a voter role.
To be a **proxy** and vote in the SBS, you must have a proxy role.

To register to become a proxy or voter in the SBS:

- Go to 'My User Profile'
- Select 'Click Here' to request additional permissions
- Select 'Voter' or 'Proxy Voter'

Commenting

Use the electronic form to submit comments on the standard(s). If you experience any difficulties in using the electronic form, contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Join Ballot Pools

Ballot pools are currently being formed. Registered Ballot Body members must join the ballot pools to be eligible to cast a ballot. Registered Ballot Body members may join the ballot pools here.

NOTE: Initially, separate ballot pools were incorrectly created for PRC-004-5 and PRC-010-2. The SBS has been updated with one ballot pool to combine PRC-004-5 and PRC-010-2. If you have already joined the separate ballot pools, please register in the combined ballot pool.

RSAWs

The draft RSAWs for the standards **PRC-004-5 – Protection System Misoperation Identification and Correction and PRC-010-2 – Under Voltage Load Shedding** are posted on the project page. Submit comments regarding the draft RSAWs to RSAWfeedback@nerc.net**.**

Next Steps

An initial ballot for the standards and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 27 through April 7, 2015.**

For information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Scott Barfield-McGinnis (via email), or by phone at (404) 446-9689.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey Report

Survey Details

Name 2008-02.2 Phase 2 UVLS PRC-004-5 & PRC-010-5

Description

Start Date 2/20/2015

End Date 4/8/2015

Associated Ballots

2008-02.2 Phase 2 UVLS PRC-004-5 & PRC-010-2 IN 1 ST

Survey Questions

See the Unofficial Comment Form on the Project Page for additional background information.

If you would like to bypass taking the survey, click the radio button and scroll down to submit the survey.

This will allow you to view Social Survey and agree / disagree with an already posted comment using the "thumbs up / thumbs down" feature.

Submitting a "thumbs up / thumbs down" on another entity's comment enables a negative vote to count in the

calculation of consensus.

I want to bypass taking the survey

1. Do you agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2?

If not, please provide comments and suggestions to improve clarity.

Yes
No

Responses By Question

See the Unofficial Comment Form on the Project Page for additional background information.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dana Wheelock - Seattle City Light - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Jones - National Grid USA - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Shanahan - National Grid USA - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Stephen Pogue - M and A Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shari Heino - Brazos Electric Power Cooperative, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shari Heino - Brazos Electric Power Cooperative, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barb Nutter - Other - NA - Not Applicable - NA - Not Applicable

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Catherine Wesley - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Evans-Mongeon - Utility Services, Inc. - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name: Hydro One Comment on Project 2008-02.2.docx

Likes: 0

Dislikes: 0

George Tatar - Black Hills Corporation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Shipps - Lakeland Electric - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Hydro One Networks, Inc. - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name: Hydro One's additional comments on Project 2008-02.2.docx

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bernard Johnson - Oglethorpe Power Corporation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

If you would like to bypass taking the survey, click the radio button and scroll down to submit the survey.

This will allow you to view Social Survey and agree / disagree with an already posted comment using the "thumbs up / thumbs down" feature.

Submitting a "thumbs up / thumbs down" on another entity's comment enables a negative vote to count in the calculation of consensus.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 - TRE

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dana Wheelock - Seattle City Light - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Jones - National Grid USA - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Shanahan - National Grid USA - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Stephen Pogue - M and A Electric Power Cooperative - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shari Heino - Brazos Electric Power Cooperative, Inc. - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shari Heino - Brazos Electric Power Cooperative, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barb Nutter - Other - NA - Not Applicable - NA - Not Applicable

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Catherine Wesley - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Evans-Mongeon - Utility Services, Inc. - 4 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

George Tatar - Black Hills Corporation - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Shipps - Lakeland Electric - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Hydro One Networks, Inc. - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bernard Johnson - Oglethorpe Power Corporation - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

1. Do you agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2?

If not, please provide comments and suggestions to improve clarity.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dana Wheelock - Seattle City Light - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

PRC-010-2, R5:
UVLS entities should have input in the development of the CAP, as opposed to simply having it provided to them. We suggest adding the phrase “in accordance with the UVLS entities” so that R5 instead reads… “Each Planning Coordinator or Transmission Planner that identifies deficiencies in its UVLS Program during an assessment performed in either Requirement R3 or R4 shall, in accordance with the UVLS entities, develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities…”

While AEP is supportive of the overall direction and substance of the proposed changes, we have chosen to vote negative driven by our objections to not involving the UVLS entities in the development of the CAP in R5.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: Yes

Answer Comment:

The proposed revisions appear to address Misoperation identification and correction of UVLS equipment. However, there may be some cases in which the timeframes in PRC-004-5 and PRC-010-2 are not completely compatible. Specifically, under PRC-010-2 Requirement R4, the Planning Coordinator (PC) or Transmission Planner (TP) has 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate to perform an assessment to evaluate the performance (i.e., operaton and non-operation) of the UVLS Program equipment. However, under PRC-004-5 Requirement R1, each Transmission Owner (TO) and Distribution Provider (DP) that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 only has 120 calendar days of the BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation. It seems like a TO or DP would have to determine if there was a Misoperation before the PC or TP might have completed their assessment. Could this result in premature determination by a TO or DP; or could a TO or DP come to a different conclusion than their PC or TP? It seems like the timeframes in these requirements need to be better aligned. Alternatively, perhaps only PRC-010-1 should be revised, or perhaps the distinction between what the two standards are requiring needs to be made clearer. Another possible issue is that each standard requires development of CAPs, and the timeframes required to develop the CAPs are different.

Document Name:

Likes: 0

Dislikes: 0

Michael Jones - National Grid USA - 1 -

Selected Answer: No

Answer Comment:

National Grid voted Negative regarding PRC-010-1 and continues to vote Negative regarding PRC-010-2. The concern is that R2 gives considerable authority to the Planning Coordinator or Transmission Planner. Nowhere in the new standard is there any provision for a UVLS entity such as a Transmisison Owner to comment or advise on the feasibility of the program specification, and particulary the implementation schedule. There should be an opportunity for the UVLS entity to provide input to the plan and schedule, and a mechanism for resolving disagreement. We have a similar concern with R5 with regard to the specification and executation of the Corrective Action Plan.

Please consider having separate ballots for PRC-010-2 and PRC-004-5, instead of a combined ballot.

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Shanahan - National Grid USA - 3 -

Selected Answer: No

Answer Comment:

National Grid voted Negative regarding PRC-010-1 and continues to vote Negative regarding PRC-010-2. The concern is that R2 gives considerable authority to the Planning Coordinator or Transmission Planner. Nowhere in the new standard is there any provision for a UVLS entity such as a Transmission Owner to comment or advise on the feasibility of the program specification, and particularly the implementation schedule. There should be an opportunity for the UVLS entity to provide input to the plan and schedule, and a mechanism for resolving disagreement. We have a similar concern with R5 with regard to the specification and execution of the Corrective Action Plan.

Please consider having separate ballots for PRC-010-2 and PRC-004-5, instead of a combined ballot.

Document Name:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Stephen Pogue - M and A Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shari Heino - Brazos Electric Power Cooperative, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shari Heino - Brazos Electric Power Cooperative, Inc. - 5 -

Selected Answer: No

Answer Comment: See ACES comments

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barb Nutter - Other - NA - Not Applicable - NA - Not Applicable

Selected Answer:

Answer Comment:

Team - this is a test comment from Barb Nutter

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

A general comment regarding the Applicability Section of PRC-004-5 is that the items listed under sub-Part 4.2.1 are not Facilities by NERC definition.

The addition of 4.2.3 to the Facilities Section “Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements” is not necessary. The BES definition excludes Elements that serve radial load. UVLS schemes are normally

intended to trip loads which are supplied by radial circuits (feeders), and these circuits (feeders) would not normally be included in the BES definition. It may be helpful for the drafting team to include an example in the application guideline to provide greater clarity.

In the Basis for Revision Section of what should be PRC-010-2, on page 3 of the standard, the last two sentences affirm that the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R5 will be removed. The only Rationale Box in the B. Requirements and Measures section of the standard is for R4. Should the statement read "The rationale box for Requirement R4 will be removed."

We agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and Part R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2. However, the addition of Part 4.2 to PRC-010-2 may create duplicate effort for evaluating proper operations and misoperations of UVLS equipment.

This comment is made on the basis that PRC-004-4 already requires UVLS entities (TO, GO and DP) to assess and identify whether or not misoperations were the cause of BES interrupting device(s) (which now include UVLS) operations. Through this assessment and identification process, the proper or improper operations of the UVLS equipment would have been identified and, where necessary and appropriate, corrective action plans would have been developed and implemented. To have an additional Part 4.2 which requires the Planning Coordinator or Transmission Planner to evaluate the performance (i.e., operation and non-operation) of the UVLS Program seems redundant and unnecessary, despite such evaluation is performed by different responsible entities. Propose that Part 4.2 be removed.

Additionally, it is not clear which UVLS Misoperations are the subject of the proposed revised PRC-004-5 standard. The UVLS facilities of PRC-004-5 are "Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements." The typical UVLS schemes trip circuits (feeders) that supply loads. These circuits (feeders) are not normally BES elements since they are excluded by the BES definition that became effective July 1, 2014. Clarification is needed.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:	Yes
Answer Comment:	The posted PRC-010-2 has requirement 4.2 applicable to PC and TP. However, PC/TP generally don't have the expertise for the design/engineering aspects. The SDT should consider making 4.2 applicable to the owners of the schemes.
Document Name:	
Likes:	0
Dislikes:	0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:	No
Answer Comment:	We agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2. However, the addition of Part 4.2 to PRC-010-2 may create duplicated effort for evaluating proper operations and misoperations of UVLS equipment. This comment is made on the basis that PRC-004-4 already requires UVLS entities (TO, GO and DP) to assess and identify whether or not misoperations were the cause of BES interrupting device(s) (which now include UVLS) operations. Through this assessment and identification process, the proper or improper operations of the UVLS equipment would have been identified and, where necessary and appropriate, corrective action plans would have been developed and implemented. To have an additional Part 4.2 which requires the Planning Coordinator or Transmission Planner to evaluate the performance (i.e., operation and non-operation) of the UVLS Program seems redundant and unnecessary, despite such evaluation is performed by different responsible entities. We therefore propose that Part 4.2 be removed.

Moreover, the IESO notes that the addition to the Facilities Section, bullet 4.2.3 “Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements” does not appear to be necessary. The BES definition excludes elements that serve radial load. UVLS schemes are normally intended to trip loads which are supplied by circuits (feeders). These circuits (feeders) would not normally be included in the BES definition. It may be helpful for the draft team to include an example in the application guideline to provide greater clarity.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

1) On the clean versions of PRC-010-2 and PRC-004-5, please remove the 'under' after ‘BES Element’ in the Basis for Revision on page 2 last paragraph. "The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element ***under*** is corrected under PRC-004 to address the requirements in the retired PRC-022-1."

2) PRC-004-5 and PRC-010-2 both require development of corrective action plans (CAP) with different time requirements (PRC-010-2 provides 12 months to analyze an operation. PRC-004-5 R1 requires identification in 120 days. Does the 120 days start during the 12 months of analysis or is the expectation that the Misoperation will be identified in the first 120 days if a BES Element is involved?) Can you provide examples to clarify which standard is to be referenced for developing the CAP?

3) Please explain how there is no double jeopardy having requirements for CAPS in multiple standards?

Example: An entity has a BES breaker that should have tripped during a UVLS event but did not trip. Is this reportable under PRC-010-2 or PRC-004-5? Which standard's time frame applies?

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE is concerned that an entity will not analyze a mis-operation if it does not trip a BES element. The language in PRC-004-5, "intended to trip one or more BES elements", may create a reliability gap. In the ERCOT region, there is little to no UVLS or UFLS that will or is intended to trip a BES element. It is not in the best interest of reliability to have a mis-operation occur and an entity not be required to analyze the issue and provide corrective actions.

Furthermore, there is an inconsistency with the language in PRC-010-2 and PRC-004-5 due to the use of the word "impact" indicated in PRC-010-2. In the ERCOT region, relays can have a major impact on the BES and would meet the requirements of PRC-010-2. Unfortunately, because of the language included in PRC-004-5, if entity determines that the UVLS is not intended to trip BES elements, the mis-operation would not need to be analyzed.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: No

Answer Comment:

Entergy supports comments provided by SERC PCS group.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Catherine Wesley - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Evans-Mongeon - Utility Services, Inc. - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Duke Energy agrees with the proposal made by the drafting team. We thank the drafting team for their efforts.

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

George Tatar - Black Hills Corporation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

(1) We believe that the modifications to PRC-010 and PRC-004 are duplicative and overlapping. As proposed, PRC-004 will require equipment owners to evaluate any UVLS relay that they have installed regardless of whether it is part of

an RAS, UVLS Program or installed independently for local reasons, while PRC-010 requires the PC or TP to evaluate the "performance of UVLS Program equipment" for voltage excursions. While we disagree with the TP or PC having responsibility to evaluate equipment performance, we are even more concerned that there is not a clear delineation between when PRC-004 applies for evaluating equipment performance and when PRC-010 applies. As written now, there would appear to be an overlap when UVLS relays that are part of a UVLS program operate. A simple solution to eliminate this overlap and duplication would be to strike Part 4.2. Then, the PC and TP would appropriately rely the equipment owners to perform their own evaluation, which is where the responsibility should belong.

(2) The supporting documentation such as the Basis for Revision, Guidelines and Technical Basis and Frequently Asked Questions neither adequately explain the need for duplication between PRC-004 and PRC-010 nor the demarcation for responsibility for evaluating equipment performance. In fact, these supporting documents actually are contradictory at times. For example, the end of the second paragraph states that PRC-004 does not cover the "performance (operation or non-operations) of UVLS Program equipment not covered by the strict process of PRC-004". Yet it never explains how PRC-004 does not cover the performance. We disagree and believe it does cover the performance. If the drafting team intends the performance of the equipment to be something different than whether the UVLS relays operated correctly or not, this needs further explained in the technical guidelines as there is little to no explanation of what is meant beyond correct operation of the relays. Near the end of the first paragraph for the "Guidelines for Requirement R4," the paragraph states that "Misoperation of UVLS equipment is addressed as a deficiency" in PRC-010. This seems to contradict the inclusion of all UVLS equipment installed to trip BES equipment in thePRC-004 applicability section where it is processed as a Misoperation. In the second paragraph of the response to the fourth FAQ, there is a statement that the definition of UVLS Program "does not explicitly note that the term excludes centrally controlled undervoltage-based load shedding." To the contrary, the last sentence of UVLS program quite clearly excludes centrally controlled UVLS.

(3) As proposed, PRC-004 will apply to all UVLS relays that can trip BES Elements including those that are part of a UVLS program and those that are not part of a UVLS program. That latter category include the centrally controlled UVLS or UVLS installed to protect local areas or equipment. While application of PRC-004 to UVLS installed to protect local areas may be appropriate, it is not appropriate to include those that are part of a centrally controlled system as this would be considered a RAS to which PRC-016 would apply. In the "Guideline for UVLS Program Definition," it is stated very clearly that a centrally controlled UVLS

system is a RAS.

(4) The VSLs for PRC-010 R4 were not modified in response to the modification of the requirement. It is now possible to partially meet the main requirement within the associated time frame. The VSLs should reflect this.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We agree that specific steps are needed to be taken to continuously improve the reliability of the Bulk Electric System (BES). The evaluating and documenting of the process helps to identify critical facilities (which could lead to Misoperations) and to ensure that the same issues doesn't reoccur on the system. Additionally, the documented information can be used to help develop and implement a Correction Action Plan (CAP) with accuracy when it's required. We would like to thank the drafting team for making great efforts to address the industry's needs.

Additionally, we would like to suggest to the drafting team to include the term 'undervoltage-based load shedding' to the definition of the Remedial Action Scheme for consistency. In the Compliance Assessment Approach Specifics Section (RSAW-PRC-010-2) R1…Note to Auditor, our interpretation is that the term 'undervoltage-based load shedding' is not a part of the UVLS Program and it states that this term falls under the NERC Glossary definition of Remedial Action Scheme (RAS). However if you go out to the NERC site, the current definition of Remedial Action Scheme (RAS) doesn't not contain this particular term.

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer: Yes

Answer Comment:

(1) CenterPoint Energy agrees that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5, is addressed by the proposed revisions of PRC-004-5 and PRC-010-2. However, the Company cannot support this draft of PRC-010-2 due to the current wording of Requirement R4.2.

(2) The drafting team proposes to add Requirement R4.2 to Requirement R4 in PRC-010 as follows: Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: 4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and 4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment. CenterPoint Energy believes a more relevant method to capture the essence of PRC-022 Requirements R1 and R1.5 is to revise Requirement R4.2 as follows: Whether the UVLS entity(ies) adhered to the UVLS Program specifications. With this revised wording for Requirement R4.2, the assessment required under Requirement R4 would address whether the UVLS Program resolved the undervoltage issue associated with the event and whether the UVLS entity or entities involved adhered to the established UVLS Program specifications. It would be obvious that the operation of the UVLS Program equipment performed adequately when the amount(s) of load shedding in a voltage excursion event meets the expected minimum amount(s) as specified in a UVLS Program. However, while an assessment (Requirement R4.1) may determine the voltage excursion event was resolved for the specific system conditions and specific contingency, the UVLS Program may have been developed for other system conditions and more severe contingencies. Therefore, the assessment (Requirement R4.2) must include whether the UVLS entity(ies) met the obligated amount of load shedding specified by the Planning Coordinator or Transmission Planner. With a large number of UVLS equipment components, it is possible that a small number may not operate (i.e., “non-operation”). Examples of

UVLS equipment non-operation would include the following: equipment problems such as a defective trip coil in a distribution circuit breaker or a defective relay and distribution circuit breaker unavailability due to maintenance (routine preventive or corrective) or construction (breaker replacement or station expansion). A small number of non-operations are inconsequential if the amount(s) of load shedding meets Planning Coordinator or Transmission Planner expectations. Furthermore, any deficiencies identified by either the proposed Requirement R4.1 or the revised wording for Requirement R4.2 would result in a Corrective Action Plan under Requirement R5.

Document Name:

Likes: 0

Dislikes: 0

Paul Shipps - Lakeland Electric - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Tri-State suggests changing the implementation plans for PRC-004-5 and PRC-010-2. They both use PRC-010-1 as a reference point even though it has not yet

been approved by FERC and therefore has no definitive effective date. If PRC-010-1 doesn't get approved before these versions do then, according to the implementation plans, these versions will be effective the 1st day of the 1st calendar quarter after the standards get approved by FERC. The drafting team should edit the implementation plans to allow more time for entities to prepare for the effective date if that were the case. We would suggest some language stating that the standards will become effective on the 1st day of the 1st calendar quarter that is 12 months after approval which would be similar to the time provided in PRC-010-1.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Hydro One Networks, Inc. - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: No

Answer Comment:

In PRC-004-5 Applicability section 4.2.3 I suggest using the phrase "Undervoltage Load Shedding (UVLS) Program equipment that is intended to trip one or more

BES Elements". This clarifies the equipment to be analyzed is part of a UVLS Program, which I believe is the intent.

Document Name:

Likes: 0

Dislikes: 0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bernard Johnson - Oglethorpe Power Corporation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Additional Comments

Puget Sound Energy
Karen Silverman

NERC Question:

Do you agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2? If not, please provide comments and suggestions to improve clarity.

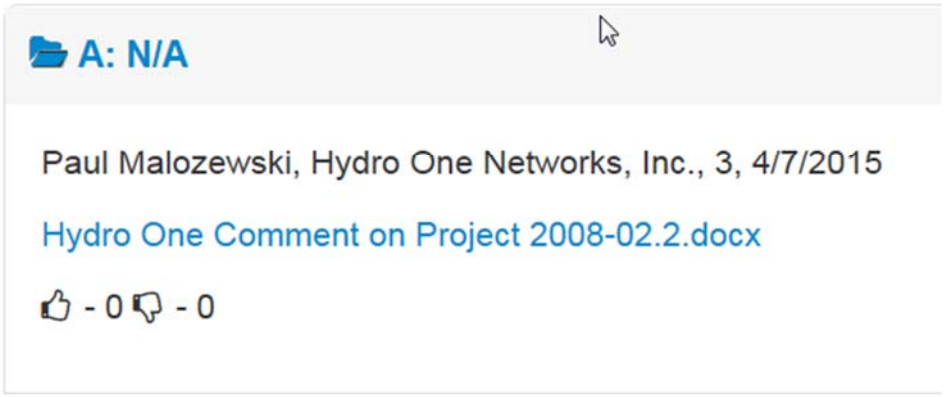
PSE Answer:

No.

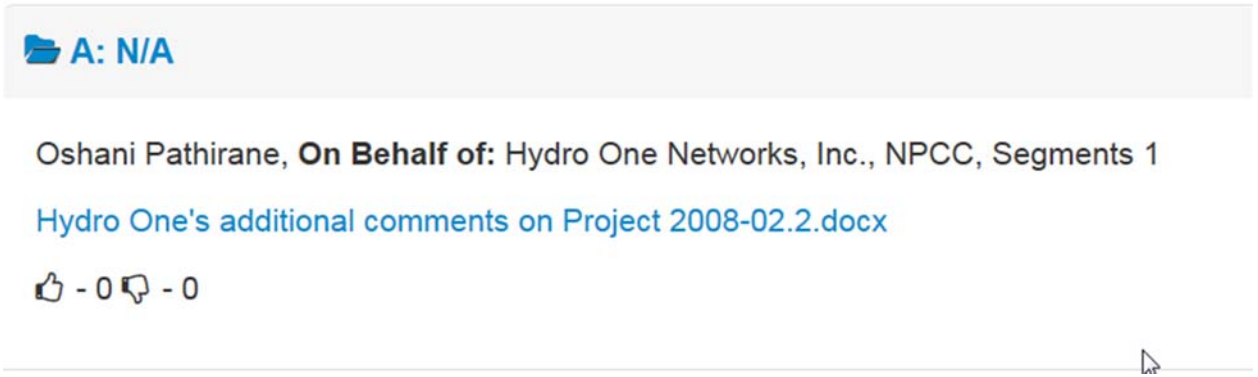
If modelled like PRC-006 (UFLS Program), PRC-010 could just govern design and documentation of UVLS Program mitigation of voltage instability, voltage collapse or Cascading impacting the Bulk Electric System. Misoperations and resulting CAPs could be covered under PRC-004-5. CAP Example #2 on Page 25 of PRC-010 should be included in PRC-004-5

Hydro One Networks
Paul Malozewski
Oshani Pathirane

Hot Answers



Hydro One supports the following comment already submitted by the TFSP: " the addition to the Facilities Section, bullet 4.2.3 "Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements" does not appear to be necessary. The BES definition excludes elements that serve radial load. UVLS schemes are normally intended to trip loads which are supplied by circuits (feeders). These circuits (feeders) would not normally be included in the BES definition. It may be helpful for the draft team to include an example in the application guideline to provide greater clarity".



Part 4.2 is specific to all devices not just BES as required under PRC-004. It puts the onus on the RC/TP to assess the success of the program if ever called upon to work. It is different than the PRC-004 requirement.

Southwest Power Pool
Charles Yeung

Question

1. Do you agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2? If not, please provide comments and suggestions to improve clarity.

☐ Yes

X No

Comments:

1. In PRC-10, the applicable entities defines "UVLS entities" as those Transmission Owners with UVLS equipment. However, R1.2, requires PCs and TPs to consider the generator ride-through capabilities in their UVLS program studies. Generator data is needed from Generator Owners. These should be applicable entities to PRC-010 as well.

We agree that the Misoperation identification and correction of UVLS equipment, as retired by PRC-022-1, Requirements R1 and R1.5, are addressed by the proposed revisions of PRC-004-5 and PRC-010-2. However, the addition of Part 4.2 to PRC-010-2 may create redundant efforts regarding evaluation of the proper operations and misoperations of UVLS equipment. More specifically, PRC-004-4 already requires UVLS entities (TO, GO and DP) to assess and identify whether or not misoperations were the cause of BES interrupting device(s) (which now include UVLS) operations). Through this assessment and identification process, the proper or improper operations of the UVLS equipment would have been identified and, where necessary and appropriate, corrective action plans would have been developed and implemented. The addition of Part 4.2, which requires the Planning Coordinator or Transmission Planner to evaluate the performance (i.e., operation and non-operation) of the UVLS Program, seems redundant to the efforts of the UVLS entities. Further, as the UVLS entities are the entities that actually operate, control, and maintain the UVLS equipment, such entities would be in the best position to perform a thorough evaluation of the operation or misoperation of such equipment. The SRC, therefore, proposes that Part 4.2 in PRC-010-2 be removed or revised to remove redundancy and ensure that the most appropriate entity is performing such assessments. Should the SDT recommend that an independent review of such assessments and corrective actions occur, such could be considered in the context of Part 4.2

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Standards Announcement

Reminder

Project 2008-02.2 Phase 2 Undervoltage Load Shedding (UVLS): Misoperations

Initial Ballot and Non-binding Poll Open through April 7, 2015

Now Available

An Initial ballot for **PRC-004-5 – Protection System Misoperation Identification and Correction** and **PRC-010-2 – Undervoltage Load Shedding** and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern, Tuesday, April 7, 2015.**

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standard and associated VRFs and VSLs by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Scott Barfield-McGinnis (via email), or at (404) 446-9689.

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404-446-2560 | www.nerc.com

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Standards Announcement

Project 2008-02.2 Phase 2 Undervoltage Load Shedding (UVLS): Misoperations

Formal Comment Period Now Open through April 7, 2015
Ballot Pool Forming Now through March 23, 2015

Balloting and commenting for this project are in the Standards Balloting & Commenting System (SBS)

Now Available

A 45-day formal comment period for **PRC-004-5 – Protection System Misoperation Identification and Correction and PRC-010-2 – Under Voltage Load Shedding** is open through **8 p.m. Eastern on Tuesday, April 7, 2015.**

Standards Balloting and Commenting System (SBS) Login, Registration, Validation and Permissions

To **comment** in the SBS, you must have a contributor, voter, or proxy role.
To **join a ballot pool and vote** in the SBS, you must have a voter role.
To be a **proxy** and vote in the SBS, you must have a proxy role.

To register to become a proxy or voter in the SBS:

- Go to 'My User Profile'
- Select 'Click Here' to request additional permissions
- Select 'Voter' or 'Proxy Voter'

Commenting

Use the electronic form to submit comments on the standard(s). If you experience any difficulties in using the electronic form, contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Join Ballot Pools

Ballot pools are currently being formed. Registered Ballot Body members must join the ballot pools to be eligible to cast a ballot. Registered Ballot Body members may join the ballot pools here.

NOTE: Initially, separate ballot pools were incorrectly created for PRC-004-5 and PRC-010-2. The SBS has been updated with one ballot pool to combine PRC-004-5 and PRC-010-2. If you have already joined the separate ballot pools, please register in the combined ballot pool.

RSAWs

The draft RSAWs for the standards **PRC-004-5 – Protection System Misoperation Identification and Correction and PRC-010-2 – Under Voltage Load Shedding** are posted on the project page. Submit comments regarding the draft RSAWs to RSAWfeedback@nerc.net**.**

Next Steps

An initial ballot for the standards and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 27 through April 7, 2015.**

For information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Scott Barfield-McGinnis (via email), or by phone at (404) 446-9689.

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Standards Announcement

Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations
PRC-004-5 and PRC-010-2

Initial Ballot and Non-Binding Poll Results

Now Available

An initial ballot for **PRC-004-5 – Protection System Misoperation Identification and Correction** and **PRC-010-2 – Under Voltage Load Shedding** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Tuesday, April 7, 2015**.

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot and non-binding poll.

Ballot	Non-Binding Poll
Quorum /Approval	Quorum/Supportive Opinions
79.93% / 84.31%	79.63% / 88.10%

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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BALLOT RESULTS

Survey: View Survey Results

Ballot Name: 2008-02.2 Phase 2 UVLS PRC-004-5 & PRC-010-2 IN 1 ST
Voting Start Date: 3/27/2015 12:01:00 AM
Voting End Date: 4/7/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 227
Total Ballot Pool: 284
Quorum: 79.93
Weighted Segment Value: 84.31

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	76	1	29	0.763	9	0.237	1	19	18
Segment: 2	9	0.5	3	0.3	2	0.2	0	0	4
Segment: 3	67	1	32	0.889	4	0.111	0	17	14
Segment: 4	20	1	14	0.875	2	0.125	0	2	2
Segment: 5	60	1	30	0.833	6	0.167	0	13	11
Segment: 6	40	1	23	0.92	2	0.08	0	9	6
Segment:	1	0	0	0	0	0	0	0	1

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8									
Segment: 9	2	0.1	1	0.1	0	0	0	0	1
Segment: 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	284	6.5	140	5.48	26	1.02	1	60	57

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	Third-Party Comments
1	Ameren - Ameren Services	Eric Scott		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	ATCO Electric	David Downey	Dan Bamber	None	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		None	N/A
1	Beaches Energy	Don Cuevas		Affirmative	N/A

	Services				
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	No Comment Submitted
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy -	William Smith		Affirmative	N/A

	FirstEnergy Corporation				
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Negative	Third-Party Comments
1	Great Plains Energy - Kansas City Power and Light Co.	Daniel Gibson		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	M and A Electric Power Cooperative	William Price		Abstain	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Abstain	N/A
1	National Grid USA	Michael Jones		Negative	Comments

					Submitted
1	NB Power Corporation	Alan MacNaughton		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	John Walker		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County,	Michiko Sell		None	N/A

	Washington				
1	Puget Sound Energy, Inc.	Denise Lietz		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Shawn Abrams		None	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A

1	Xcel Energy, Inc.	Greg Pieper		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		None	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula	Mark Wilson	Negative	Comments Submitted
2	ISO New England, Inc.	Matthew Goldberg		None	N/A
2	Midcontinent ISO, Inc.	Terry Bllke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Third-Party Comments
3	APS - Arizona Public Service Co.	Sarah Kist		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Abstain	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		None	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A

3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Abstain	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Bill Hughes	Mary Downey	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Abstain	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	Fayetteville Public Works Commission	Allen Wallace		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart	Richard Hoag	Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	Joshua Bach		Affirmative	N/A

3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Greg LeGrave		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Abstain	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Abstain	N/A
3	Northeast Utilities	Mark Kenny		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Abstain	N/A

3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A
3	Platte River Power Authority	Terry Baker		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A

3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Mary Downey	Affirmative	N/A
4	City of Winter Park	Mark Brown		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Integrys Energy Group, Inc. - Wisconsin Public	Christopher Plante		Abstain	N/A

	Service Corporation				
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Keith Morisette		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Scott Takinen		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Abstain	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A

5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Kaleb Brimhall		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Golden Spread Electric Cooperative, Inc.	Chip Koloini		None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Brett Holland		None	N/A

5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Scott Johnson		Abstain	N/A
5	JEA	John Babik		Abstain	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Liberty Electric Power LLC	Daniel Duff		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A

5	Oglethorpe Power Corporation	Bernard Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Christopher Wood		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Westar Energy	stephanie johnson		Abstain	N/A

5	Xcel Energy, Inc.	Mark Castagneri		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Negative	Third-Party Comments
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Randy Young		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Abstain	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Brenda Anderson		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Abstain	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		None	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Lincoln Electric	Eric Ruskamp		Abstain	N/A

	System				
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		None	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Stephen York		Affirmative	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Seattle City Light	Dennis Sismaet		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company -	John J. Ciza		Affirmative	N/A

	Southern Company Generation and Energy Marketing				
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Tiffany Lake		Abstain	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
7	Siemens - Siemens PTI	Frank McElvain		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	National Association of Regulatory Utility Commissioners	Jerry Maio		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2008-02.2 Phase 2 UVLS PRC-004-5 & PRC-010-2 Non-Binding Poll IN 1 NB
Voting Start Date: 3/27/2015 12:01:00 AM
Voting End Date: 4/7/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 215
Total Ballot Pool: 270
Quorum: 79.63
Weighted Segment Value: 88.1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	73	1	23	0.767	7	0.233	0	25	18
Segment: 2	9	0.5	4	0.4	1	0.1	0	0	4
Segment: 3	63	1	24	0.889	3	0.111	0	23	13
Segment: 4	17	1	10	0.909	1	0.091	0	5	1
Segment: 5	60	1	26	0.897	3	0.103	0	20	11
Segment: 6	37	1	17	1	0	0	0	14	6
Segment: 7	1	0	0	0	0	0	0	0	1

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Segment: 9	2	0.1	1	0.1	0	0	0	0	1
Segment: 10	6	0.4	3	0.3	1	0.1	0	2	0
Totals:	270	6.2	110	5.462	16	0.738	0	89	55

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	ATCO Electric	David Downey	Dan Bamber	None	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		None	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Third-Party Comments
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A

1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Negative	Third-Party Comments
1	Great Plains Energy - Kansas City Power and Light Co.	Daniel Gibson		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Negative	Third-Party Comments
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	M and A Electric Power Cooperative	William Price		Abstain	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Abstain	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted

1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	John Walker		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Denise Lietz		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A

1	Santee Cooper	Shawn Abrams		None	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		None	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted

2	Electric Reliability Council of Texas, Inc.	christina bigelow		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula	Mark Wilson	Affirmative	N/A
2	ISO New England, Inc.	Matthew Goldberg		None	N/A
2	Midcontinent ISO, Inc.	Terry Bllke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Sarah Kist		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Abstain	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		None	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Abstain	N/A

3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Abstain	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart	Richard Hoag	Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	Joshua Bach		Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles	Mike Anctil		None	N/A

	Department of Water and Power				
3	M and A Electric Power Cooperative	Stephen Pogue		Abstain	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Abstain	N/A
3	Northeast Utilities	Mark Kenny		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Abstain	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Terry Baker		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Rutherford EMC	Tom Haire		None	N/A

3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A

4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Winter Park	Mark Brown		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Christopher Plante		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Keith Morisette		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public	Scott Takinen		Affirmative	N/A

	Service Co.				
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Abstain	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Abstain	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Kaleb Brimhall		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A

5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Golden Spread Electric Cooperative, Inc.	Chip Koloini		None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Brett Holland		None	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Scott Johnson		Abstain	N/A
5	JEA	John Babik		Abstain	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Liberty Electric Power LLC	Daniel Duff		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A

5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Christopher Wood		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company	William D. Shultz		Affirmative	N/A

	Generation				
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Westar Energy	stephanie johnson		Abstain	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Randy Young		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Abstain	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Brenda Anderson		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A

6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		None	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		None	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Stephen York		Abstain	N/A

6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Seattle City Light	Dennis Sismaet		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Tiffany Lake		Abstain	N/A
7	Siemens - Siemens PTI	Frank McElvain		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	National Association of Regulatory Utility Commissioners	Jerry Maio		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability	Rachel Coyne		Negative	Comments

	Entity, Inc.				Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2008-02.2 Phase 2 UVLS PRC-004-5 & PRC-010-5

Comment Period Start Date: 2/20/2015

Comment Period End Date: 4/8/2015

Associated Ballots: 2008-02.2 Phase 2 UVLS PRC-004-5 & PRC-010-2 IN 1 ST

If you feel that you comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Standards, Valerie Agnew (via email) or at (404) 446-2566.

Summary of Changes

The introductory section of both PRC-004-5 and PRC-010-2 standards were updated. The Development Step Completed and Description of Current Draft were updated. The Project Development Background received three clarifying edits and in PRC-010-2, a missing footnote was added and the reference to R5 was corrected to R4. Other cosmetic cleanup was performed to bring the standard into conformity with the NERC style guide.

Both Implementation Plans were clarified in the General Considerations to better explain the two standard going forward together.

The project Mapping Document was augmented to demonstrate how PRC-004-5 addresses the Corrective Action Plan provision from the retired PRC-022-1 in the first phase of the project.

Summary:
There were at least three comments that raised issues that were related to the work the standard drafting team (SDT) completed during the development of PRC-010-1. The SDT was unable to address the comment because it was beyond the scope of work. At least two commenters noted that either the proposed PRC-010-1, Requirement R4, Part 4.2 or PRC-004-5, Applicability 4.2.3 was unnecessary. The SDT did not make a change, but rather explained the rationale why both are important to reliability. There were about three questions about the perceived overlap of PRC-004-5 and PRC-010-1 and the timing differences. The SDT did not make any changes, but explained the intent between the two standards and the reason that there are two different time periods. One commenter suggested allowing an additional 12 months for implementation. The SDT believed that was unnecessary because the UVLS changes do not represent a significant burden to industry and only impact a few entities. Last, there were at least two comments that the PRC-004-5 applicability was meaningless because radial lines would not be Bulk Electric System (BES) Elements. The SDT added the provision in PRC-004-5 to cover the few BES UVLS relays currently applied in some systems across North America as well as cover any future changes that could occur to the BES definition.

1. ***Do you agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2?***

   If not, please provide comments and suggestions to improve clarity.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Ken Lindberg - Bryan Texas Utilities - 5 - TRE

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 3 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Dennis Minton - Florida Keys Electric Cooperative Assoc. - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Dana Wheelock - Seattle City Light - 3 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

PRC-010-2, R5:
UVLS entities should have input in the development of the CAP, as opposed to simply having it provided to them. We suggest adding the phrase “in accordance with the UVLS entities” so that R5 instead reads… “Each Planning Coordinator or Transmission Planner that identifies deficiencies in its UVLS Program during an assessment

performed in either Requirement R3 or R4 shall, in accordance with the UVLS entities, develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities…"

While AEP is supportive of the overall direction and substance of the proposed changes, we have chosen to vote negative driven by our objections to not involving the UVLS entities in the development of the CAP in R5.

Response: The drafting team thanks you for your comments. The comment pertains to work completed under the first phase of the UVLS project that developed version 1 of PRC-010 and the retired PRC-022-1. This phase 2 work only pertains to addressing UVLS equipment Misoperation and relies on the previously balloted and adopted PRC-010-1.

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Québec TransÉnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:	Yes
Answer Comment:	The proposed revisions appear to address Misoperation identification and correction of UVLS equipment. However, there may be some cases in which the timeframes in PRC-004-5 and PRC-010-2 are not completely compatible. Specifically, under PRC-010-2 Requirement R4, the Planning Coordinator (PC) or Transmission Planner (TP) has 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate to perform an assessment to evaluate the performance (i.e., operaton and non-operation) of the UVLS Program equipment. However, under PRC-004-5 Requirement R1, each Transmission Owner (TO) and Distribution Provider (DP) that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 only has 120 calendar days of the BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation. It seems like a TO or DP would have to determine if there was a Misoperation before the PC or TP might have completed their assessment. Could this result in premature determination by a TO or DP; or could a TO or DP come to a different conclusion than their PC or TP? It seems like the timeframes in these requirements need to be better aligned. Alternatively, perhaps only PRC-010-1 should be revised, or perhaps the distinction between what the two standards are requiring needs to be made clearer. Another possible issue is that each standard requires development of CAPs, and the timeframes required to develop the CAPs are different.
Response:	The drafting team thanks you for your comment. Entities that experience an operation of the UVLS equipment that trip one or more BES Elements (irrespective of a voltage excursion) must address reviews in a shorter time (PRC-004). Likewise, planners will assess the performance of the UVLS Program following an event that resulted in a voltage

excursion for which its UVLS Program was designed to operate. The assessment determines whether the UVLS equipment operated according to the design of the program, which will include the operation or non-operation of any UVLS equipment within the program.

The following addresses the timing between the proposed PRC-004-5 and PRC-010-2.

For an event that resulted in a voltage excursion for which the UVLS Program was designed to operate, it is acceptable for an applicable entity under the proposed PRC-004-5 to begin reviewing the operation. If the entity determines a Misoperation occurred, it may develop a Corrective Action Plan (CAP). Developing the CAP and correcting the Misoperation could occur in advance of the assessment conducted by the Planning Coordinator (PC) or Transmission Planner (TP) under the proposed PRC-010-2. The drafting team would anticipate the applicable entity under PRC-004 to communicate their findings; therefore, the PC or TP would account for the findings during the post event assessment.

For reliability, it is important to address UVLS that trip BES Elements on a timely basis. The PC or TP under PRC-010 is allocated an amount of time that is commensurate with the work necessary to perform the post event analysis. For example, collecting event data such as voltage, confirming UVLS settings, potential Misoperation information, and performing the analysis to evaluate the overall performance of the UVLS Program.

Likes: 0

Dislikes: 0

Michael Jones - National Grid USA - 1 -

Selected Answer:	No
Answer Comment:	National Grid voted Negative regarding PRC-010-1 and continues to vote Negative regarding PRC-010-2. The concern is that R2 gives considerable authority to the Planning Coordinator or Transmission Planner. Nowhere in the new standard is there any provision for a UVLS entity such as a Transmisison Owner to comment or advise on the feasibility of the program specification, and particulary the implementation schedule. There should be an opportunity for the UVLS entity to provide input to the plan and schedule, and a mechanism for resolving disagreement. We have a similar concern with R5 with regard to the specification and executation of the Corrective Action Plan. Please consider having separate ballots for PRC-010-2 and PRC-004-5, instead of a combined ballot.
Response:	The drafting team thanks you for your comments. The comment pertains to work completed under the first phase of the UVLS project that developed version 1 of PRC-010 and retired PRC-022. This phase 2 work only pertains to addressing UVLS equipment Misoperation and relies on the previously balloted and adopted PRC-010-1.
Likes:	0
Dislikes:	0

Michael Shaw - Lower Colorado River Authority - 6 -

Selected Answer:	Yes
Answer Comment:	

Response:

Likes: 0

Dislikes: 0

Brian Shanahan - National Grid USA - 3 -

Selected Answer: No

Answer Comment: National Grid voted Negative regarding PRC-010-1 and continues to vote Negative regarding PRC-010-2. The concern is that R2 gives considerable authority to the Planning Coordinator or Transmission Planner. Nowhere in the new standard is there any provision for a UVLS entity such as a Transmission Owner to comment or advise on the feasibility of the program specification, and particularly the implementation schedule. There should be an opportunity for the UVLS entity to provide input to the plan and schedule, and a mechanism for resolving disagreement. We have a similar concern with R5 with regard to the specification and execution of the Corrective Action Plan.

Please consider having separate ballots for PRC-010-2 and PRC-004-5, instead of a combined ballot.

Response: The drafting team thanks you for your comments. The comment pertains to work completed under the first phase of the UVLS project that developed version 1 of PRC-010 and retired PRC-022. This phase 2 work only pertains to addressing UVLS equipment Misoperation and relies on the previously balloted and adopted PRC-010-1.

Likes: 0

Dislikes: 0

Stephen Pogue - M and A Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Shari Heino - Brazos Electric Power Cooperative, Inc. - 5 -

Selected Answer: No

Answer Comment:

See ACES comments

Response:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Selected Answer: No

Answer Comment:

A general comment regarding the Applicability Section of PRC-004-5 is that the items listed under sub-Part 4.2.1 are not Facilities by NERC definition.

The addition of 4.2.3 to the Facilities Section "Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements" is not necessary. The BES definition excludes Elements that serve radial load. UVLS schemes are normally intended to trip loads which are supplied by radial circuits (feeders), and these circuits (feeders) would not normally be included in the BES definition. It may be helpful for the drafting team to include an example in the application guideline to provide greater clarity.

In the Basis for Revision Section of what should be PRC-010-2, on page 3 of the standard, the last two sentences affirm that the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R5 will be removed. The only Rationale Box in the B. Requirements and Measures section of the standard is for R4. Should the statement read "The rationale box for Requirement R4 will be removed."

We agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and Part R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2. However, the addition of Part 4.2 to PRC-010-2 may create duplicate effort for evaluating proper operations and misoperations of UVLS equipment.

This comment is made on the basis that PRC-004-4 already requires UVLS entities (TO, GO and DP) to assess and identify whether or not misoperations were the cause of BES interrupting device(s) (which now include UVLS) operations. Through this assessment and identification process, the proper or improper operations of the UVLS equipment would have been identified and, where necessary and appropriate, corrective action plans would have been developed and implemented. To have an additional Part 4.2 which requires the Planning Coordinator or Transmission Planner to evaluate the performance (i.e., operation and non-operation) of the UVLS Program seems redundant and unnecessary, despite such evaluation is performed by different responsible entities. Propose that Part 4.2 be removed.

Additionally, it is not clear which UVLS Misoperations are the subject of the proposed revised PRC-004-5 standard. The UVLS facilities of PRC-004-5 are "Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements." The typical UVLS schemes trip circuits (feeders) that supply loads. These circuits (feeders) are not normally BES elements since they are excluded by the BES definition that became effective July 1, 2014. Clarification is needed.

Response:

The drafting team thanks you for your comments. The section titles "Functional Entities" and "Facilities" found in the standard do not refer specifically to the *Glossary of Terms Used in NERC Reliability Standards* or the definitions identified in the NERC Rules of Procedure.

With regard to the comment about radial lines, the applicability in the proposed PRC-004-5 addresses the potential for the existence of UVLS that trip one or more BES Elements today, or in the future. For example, if a change were to occur in the BES definition, UVLS equipment would be properly addressed to avoid a gap in reliability. The drafting team believes the distinction is clear and an example is not necessary.

The observation concerning the Rational Box for Requirement R5 is correct. This text should reference Requirement R4. Change made.

Concerning the duplication of effort between the proposed PRC-004-5 and PRC-010-2, the drafting team notes that PRC-004 requires the owners of UVLS to evaluate the relay when it trips a BES interrupting device. In PRC-010, the planners evaluate the performance of the UVLS Program with consideration whether the UVLS equipment operated or did not operate in accordance with the UVLS Program design.

For an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, it is acceptable for an applicable entity under the proposed PRC-004-5 to begin reviewing the operation. If the entity determines a Misoperation occurred, it may develop a Corrective Action Plan (CAP). Developing the CAP and correcting the Misoperation could occur in advance of the assessment conducted by the Planning Coordinator (PC) or Transmission Planner (TP) under the proposed PRC-010-2. The drafting team would anticipate the applicable entity under PRC-004 to communicate their findings; therefore, the PC or TP would account for the findings during the post event assessment.

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: Yes

Answer Comment: The posted PRC-010-2 has requirement 4.2 applicable to PC and TP. However, PC/TP generally don't have the expertise for the design/engineering

aspects. The SDT should consider making 4.2 applicable to the owners of the schemes.

Response: The drafting team thanks you for your comment. The intent of the proposed PRC-010-2, Requirement R4, Part 4.2 is to require the Planning Coordinator or Transmission Planner to assess the UVLS Program following an event that resulted in a voltage excursion for which its UVLS Program was designed to operate. The planner will collect information concerning the event in order to conduct an assessment whether (4.1) the program resolved the undervoltage issues associated with the event, and (4.2) the program equipment operated or did not operate as expected according to the characteristics of the event. The assessment by its very nature assesses the equipment at the program level and not the design/engineering aspects applicable to UVLS Entities.

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: No

Answer Comment: We agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2. However, the addition of Part 4.2 to PRC-010-2 may create duplicated effort for evaluating proper operations and misoperations of UVLS equipment.

This comment is made on the basis that PRC-004-4 already requires UVLS entities (TO, GO and DP) to assess and identify whether or not misoperations were the cause of BES interrupting device(s) (which now include UVLS) operations. Through this

assessment and identification process, the proper or improper operations of the UVLS equipment would have been identified and, where necessary and appropriate, corrective action plans would have been developed and implemented. To have an additional Part 4.2 which requires the Planning Coordinator or Transmission Planner to evaluate the performance (i.e., operation and non-operation) of the UVLS Program seems redundant and unnecessary, despite such evaluation is performed by different responsible entities.

We therefore propose that Part 4.2 be removed.

Moreover, the IESO notes that the addition to the Facilities Section, bullet 4.2.3 "Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements" does not appear to be necessary. The BES definition excludes elements that serve radial load. UVLS schemes are normally intended to trip loads which are supplied by circuits (feeders). These circuits (feeders) would not normally be included in the BES definition. It may be helpful for the draft team to include an example in the application guideline to provide greater clarity.

Response:

The drafting team thanks you for your comments.

Concerning the duplication of effort between the proposed PRC-004-5 and PRC-010-2, the drafting team notes that PRC-004 requires the owners of UVLS to evaluate the relay when it trips a BES interrupting device. In PRC-010, the planners evaluate the performance of the UVLS Program with consideration whether the UVLS equipment operated or did not operate in accordance with the UVLS Program design.

For an event that resulted in a voltage excursion for which the UVLS Program was designed to operate, it is acceptable for an applicable entity under the proposed PRC-004-5 to begin reviewing the operation. If the entity determines a Misoperation occurred, it may develop a Corrective Action Plan (CAP). Developing the CAP and correcting the Misoperation could occur in advance of the assessment conducted by the Planning Coordinator (PC) or Transmission Planner (TP) under the proposed PRC-010-2. The drafting team would anticipate the applicable entity under PRC-004 to communicate

their findings; therefore, the PC or TP would account for the findings during the post event assessment.

With regard to the comment about radial lines, the applicability in the proposed PRC-004-5 addresses the potential for the existence of UVLS that trip one or more BES Elements today, or in the future. For example, if a change were to occur in the BES definition, UVLS equipment would be properly addressed to avoid a gap in reliability. The drafting team believes the distinction is clear and an example is not necessary.

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Selected Answer: No

Answer Comment:

1) On the clean versions of PRC-010-2 and PRC-004-5, please remove the 'under' after 'BES Element' in the Basis for Revision on page 2 last paragraph. "The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element ***under*** is corrected under PRC-004 to address the requirements in the retired PRC-022-1."

2) PRC-004-5 and PRC-010-2 both require development of corrective action plans (CAP) with different time requirements (PRC-010-2 provides 12 months to analyze an operation. PRC-004-5 R1 requires identification in 120 days. Does the 120 days start during the 12 months of analysis or is the expectation that the Misoperation will be

identified in the first 120 days if a BES Element is involved?) Can you provide examples to clarify which standard is to be referenced for developing the CAP?

3) Please explain how there is no double jeopardy having requirements for CAPS in multiple standards?

Example: An entity has a BES breaker that should have tripped during a UVLS event but did not trip. Is this reportable under PRC-010-2 or PRC-004-5? Which standard's time frame applies?

Response:

The drafting team thanks you for your comments.
1) The observation about the additional "under" has been revised as noted. Change made.
2) The 120 calendar days begins when a BES interrupting device operates as required by the proposed PRC-004-5, Requirement R1; therefore, it would start at the same point defined by the proposed PRC-010-2. See #3 about which standard is addressing the Corrective Action Plan (CAP).
3) For an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, the planner would assess UVLS equipment under the proposed PRC-010-2, Requirement R4, Part 4.2 and provide a CAP, if necessary, to the UVLS Entity. Under the proposed PRC-004-5, the UVLS equipment owner would develop a CAP on its own to address any BES UVLS equipment Misoperation.

(From the "Example") However, in the example above the UVLS owner would not be obligated to review the UVLS relay because a BES interrupting device did not operate (see PRC-004-5, Requirement R1). In this case, the planner would identify the non-operation of the UVLS that should have tripped the BES Element. Additionally, the planner would develop a Corrective Action Plan (CAP) for the UVLS Entity to implement. The Misoperation of UVLS is not reportable by either PRC-010 or PRC-004, but is reportable by the equipment owner under Section 1600 of the NERC Rules of Procedure, Request for Data or Information.

Likes:	0
Dislikes:	0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	No
Answer Comment:	Texas RE is concerned that an entity will not analyze a mis-operation if it does not trip a BES element. The language in PRC-004-5, "intended to trip one or more BES elements", may create a reliability gap. In the ERCOT region, there is little to no UVLS or UFLS that will or is intended to trip a BES element. It is not in the best interest of reliability to have a mis-operation occur and an entity not be required to analyze the issue and provide corrective actions. Furthermore, there is an inconsistency with the language in PRC-010-2 and PRC-004-5 due to the use of the word "impact" indicated in PRC-010-2. In the ERCOT region, relays can have a major impact on the BES and would meet the requirements of PRC-010-2. Unfortunately, because of the language included in PRC-004-5, if entity determines that the UVLS is not intended to trip BES elements, the mis-operation would not need to be analyzed.
Response:	The drafting team thanks you for your comments and contends that entities will address UVLS (not associated with a UVLS Program) that does not trip a BES Element because load would be lost. Under the UVLS Program, such UVLS equipment is required to be assessed for an event that resulted in a voltage excursion for which its UVLS Program was designed to operate. Therefore, there is no inconsistency or gap in addressing UVLS equipment.

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: No

Answer Comment: Entergy supports comments provided by SERC PCS group.

Response: The drafting team thanks you for your support of SERC PCS group comments.

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Catherine Wesley - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Brian Evans-Mongeon - Utility Services, Inc. - 4 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment: Duke Energy agrees with the proposal made by the drafting team. We thank the drafting team for their efforts.

Response: The drafting team thanks you for your comments.

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

George Tatar - Black Hills Corporation - 5 -

Selected Answer:

Answer Comment:

Response:

Likes:	0
Dislikes:	0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Selected Answer:	No
Answer Comment:	(1) We believe that the modifications to PRC-010 and PRC-004 are duplicative and overlapping. As proposed, PRC-004 will require equipment owners to evaluate any UVLS relay that they have installed regardless of whether it is part of an RAS, UVLS Program or installed independently for local reasons, while PRC-010 requires the PC or TP to evaluate the "performance of UVLS Program equipment" for voltage excursions. While we disagree with the TP or PC having responsibility to evaluate equipment performance, we are even more concerned that there is not a clear delineation between when PRC-004 applies for evaluating equipment performance and when PRC-010 applies. As written now, there would appear to be an overlap when UVLS relays that are part of a UVLS program operate. A simple solution to eliminate this overlap and duplication would be to strike Part 4.2. Then, the PC and TP would appropriately rely the equipment owners to perform their own evaluation, which is where the responsibility should belong. (2) The supporting documentation such as the Basis for Revision, Guidelines and Technical Basis and Frequently Asked Questions neither adequately explain the need for duplication between PRC-004 and PRC-010 nor the demarcation for responsibility for evaluating equipment performance. In fact, these supporting documents actually are contradictory at times. For example, the end of the second paragraph states that PRC-004 does not cover the "performance (operation or non-operations) of UVLS Program equipment not covered by the strict process of PRC-004". Yet it never explains how PRC-004 does not cover the performance. We disagree and believe it does cover the performance. If the drafting team intends the performance of the

equipment to be something different than whether the UVLS relays operated correctly or not, this needs further explained in the technical guidelines as there is little to no explanation of what is meant beyond correct operation of the relays. Near the end of the first paragraph for the "Guidelines for Requirement R4," the paragraph states that "Misoperation of UVLS equipment is addressed as a deficiency" in PRC-010. This seems to contradict the inclusion of all UVLS equipment installed to trip BES equipment in thePRC-004 applicability section where it is processed as a Misoperation. In the second paragraph of the response to the fourth FAQ, there is a statement that the definition of UVLS Program "does not explicitly note that the term excludes centrally controlled undervoltage-based load shedding." To the contrary, the last sentence of UVLS program quite clearly excludes centrally controlled UVLS.

(3) As proposed, PRC-004 will apply to all UVLS relays that can trip BES Elements including those that are part of a UVLS program and those that are not part of a UVLS program. That latter category include the centrally controlled UVLS or UVLS installed to protect local areas or equipment. While application of PRC-004 to UVLS installed to protect local areas may be appropriate, it is not appropriate to include those that are part of a centrally controlled system as this would be considered a RAS to which PRC-016 would apply. In the "Guideline for UVLS Program Definition," it is stated very clearly that a centrally controlled UVLS system is a RAS.

(4) The VSLs for PRC-010 R4 were not modified in response to the modification of the requirement. It is now possible to partially meet the main requirement within the associated time frame. The VSLs should reflect this.

Response:

The drafting team thanks you for your comments.

1) Concerning the duplication of effort between the proposed PRC-004-5 and PRC-010-2, the drafting team notes that PRC-004 requires the owners of UVLS to evaluate the relay when it trips a BES interrupting device. In PRC-010, the planners evaluate the performance of the UVLS Program with consideration whether the UVLS equipment operated or did not operate in accordance with the UVLS Program design.

2) The drafting team notes that PRC-004 requires the owners of UVLS to evaluate the relay when it trips a BES interrupting device. In PRC-010, the planners evaluate the

performance of the UVLS Program with consideration whether the UVLS equipment operated or did not operate in accordance with the UVLS Program design.

3) UVLS that trips one or more BES Elements would be applicable to PRC-004. UVLS under PRC-010 is applicable to UVLS defined by a UVLS Program, which specifically excludes centrally controlled UVLS by definition. Centrally controlled UVLS is a Remedial Action Scheme (RAS) by the adopted definition. So, RAS standards would apply to centrally controlled UVLS. It is possible that UVLS that trips a BES Element to be included within a UVLS Program; however, this is expected to be rare.

4) The team contends that both 4.1 and 4.2 must be performed together to ensure an adequate assessment of the UVLS Program; therefore, the drafting team is not proposing a Violation Severity Level which accounts for partial performance.

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer: Yes

Answer Comment: We agree that specific steps are needed to be taken to continuously improve the reliability of the Bulk Electric System (BES). The evaluating and documenting of the process helps to identify critical facilities (which could lead to Misoperations) and to ensure that the same issues doesn't reoccur on the system. Additionally, the documented information can be used to help develop and implement a Correction Action Plan (CAP) with accuracy when it's required. We would like to thank the drafting team for making great efforts to address the industry's needs.

Additionally, we would like to suggest to the drafting team to include the term 'undervoltage-based load shedding' to the definition of the Remedial Action Scheme for consistency. In the Compliance Assessment Approach Specifics Section (RSAW-PRC-010-2) R1…Note to Auditor, our interpretation is that the term 'undervoltage-based load shedding' is not a part of the UVLS Program and it states that this term falls under the NERC Glossary definition of Remedial Action Scheme (RAS). However if you go out to the NERC site, the current definition of Remedial Action Scheme (RAS) doesn't not contain this particular term.

Response: The drafting team thanks you for your comment and notes that revising the NERC Board of Trustees adopted definition of "Remedial Action Scheme" (RAS) is not with the scope of this project. A RAS currently addresses centrally controlled UVLS schemes. Also, the drafting team has deleted "-based" from undervoltage load shedding in the "Note to Auditor" for clarity. The change was made to the RSAW and submitted to NERC Compliance. Please note that RSAWs are not posted during the final ballot.

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer: Yes

Answer Comment:

(1) CenterPoint Energy agrees that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5, is addressed by the proposed revisions of PRC-004-5 and PRC-010-2. However, the Company cannot support this draft of PRC-010-2 due to the current wording of Requirement R4.2.

(2) The drafting team proposes to add Requirement R4.2 to Requirement R4 in PRC-

	010 as follows: Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: 4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and 4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment. CenterPoint Energy believes a more relevant method to capture the essence of PRC-022 Requirements R1 and R1.5 is to revise Requirement R4.2 as follows: Whether the UVLS entity(ies) adhered to the UVLS Program specifications. With this revised wording for Requirement R4.2, the assessment required under Requirement R4 would address whether the UVLS Program resolved the undervoltage issue associated with the event and whether the UVLS entity or entities involved adhered to the established UVLS Program specifications. It would be obvious that the operation of the UVLS Program equipment performed adequately when the amount(s) of load shedding in a voltage excursion event meets the expected minimum amount(s) as specified in a UVLS Program. However, while an assessment (Requirement R4.1) may determine the voltage excursion event was resolved for the specific system conditions and specific contingency, the UVLS Program may have been developed for other system conditions and more severe contingencies. Therefore, the assessment (Requirement R4.2) must include whether the UVLS entity(ies) met the obligated amount of load shedding specified by the Planning Coordinator or Transmission Planner. With a large number of UVLS equipment components, it is possible that a small number may not operate (i.e., "non-operation"). Examples of UVLS equipment non-operation would include the following: equipment problems such as a defective trip coil in a distribution circuit breaker or a defective relay and distribution circuit breaker unavailability due to maintenance (routine preventive or corrective) or construction (breaker replacement or station expansion). A small number of non-operations are inconsequential if the amount(s) of load shedding meets Planning Coordinator or Transmission Planner expectations. Furthermore, any deficiencies identified by either the proposed Requirement R4.1 or the revised wording for Requirement R4.2 would result in a Corrective Action Plan under Requirement R5.
Response:	The drafting team thanks you for your comment. 1) See #2. 2) The proposed wording "whether the UVLS entity or entities involved adhered to the established UVLS Program specifications" places judgement on UVLS owners as to

whether the entity complied with the Planning Coordinator or Transmission Planner specification. This concern is addressed by PRC-010, Requirement R2, which requires "[e]ach UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5."

The drafting team contends that post-event assessments are intended to assure the UVLS Program operated consistent with its design. The failure or Misoperation of one of more UVLS relays could occur, but should not impact the overall performance of the UVLS Program. The Planning Coordinator or Transmission Planner with the proposed PRC-010, Requirement R4, Part 4.2 is intended to ensure the assessment addresses the operation and non-operation of UVLS Program equipment according to the characteristics of the event. The assessment in Requirement R4 should reveal items suggested in the above comment examples could be valid reasons for lack of performance. Part 4.2 is intended to require the planner to assess issues provided in the comment examples, and more specifically any operation or non-operation of UVLS Program equipment.

Likes: 0

Dislikes: 0

Paul Shipps - Lakeland Electric - 6 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Tri-State suggests changing the implementation plans for PRC-004-5 and PRC-010-2. They both use PRC-010-1 as a reference point even though it has not yet been approved by FERC and therefore has no definitive effective date. If PRC-010-1 doesn't get approved before these versions do then, according to the implementation plans, these versions will be effective the 1st day of the 1st calendar quarter after the standards get approved by FERC. The drafting team should edit the implementation plans to allow more time for entities to prepare for the effective date if that were the case. We would suggest some language stating that the standards will become effective on the 1st day of the 1st calendar quarter that is 12 months after approval which would be similar to the time provided in PRC-010-1.

Response:

The drafting team thanks you for your comment. NERC Legal aided the drafting team in constructing the Implementation Plan. It is constructed in a manner to allow the proposed PRC-010-2 to surpass PRC-010-1 and stand on its own, or become effective very soon after the approval of PRC-010-1. Also, not keying both standards off of PRC-010-2 approval could lead to an unintentional gap in enforcement. The drafting team contends that an additional 12-month implementation beyond the previous versions is unnecessary.

Likes: 0

Dislikes: 0

Oshani Pathirane - Hydro One Networks, Inc. - 1 - NPCC

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: No

Answer Comment: In PRC-004-5 Applicability section 4.2.3 I suggest using the phrase "Undervoltage Load Shedding (UVLS) Program equipment that is intended to trip one or more BES Elements". This clarifies the equipment to be analyzed is part of a UVLS Program, which I believe is the intent.

Response:	The drafting team thanks you for your comment. The two proposed standards are constructed to address two different issues. The proposed PRC-004-5 is addressing UVLS that trip one or more BES Elements, which may include relays in a UVLS Program; however, if that is the case, it would expected to be rare. The proposed PRC-010-2 addresses UVLS Program equipment, which typically trips distribution equipment and would not be applicable to the proposed PRC-004-5.
Likes:	0
Dislikes:	0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:	Yes
Answer Comment:	
Response:	
Likes:	0
Dislikes:	0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Bernard Johnson - Oglethorpe Power Corporation - 5 -

Selected Answer:

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Additional Comments

Puget Sound Energy
Karen Silverman

NERC Question: Do you agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is
addressed by the proposed revisions of PRC-004-5 and PRC-010-2? If not, please provide comments and suggestions to improve clarity.

PSE Answer: No.

If modelled like PRC-006 (UFLS Program), PRC-010 could just govern design and documentation of UVLS Program mitigation of voltage instability, voltage collapse or Cascading impacting the Bulk Electric System. Misoperations and resulting CAPs could be covered under PRC-004-5. CAP Example #2 on Page 25 of PRC-010 should be included in PRC-004-5

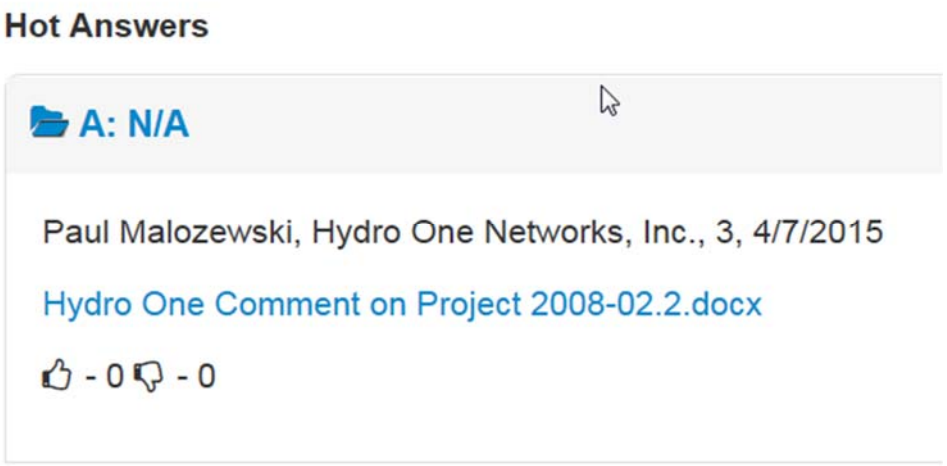
Response: The drafting team thanks you for your comment. Entities that experience an operation of the UVLS equipment that trip one or more BES Elements (irrespective of a voltage excursion) must address reviews in a shorter time (PRC-004). Likewise, planners will assess the performance of the UVLS Program following an event that resulted in a voltage excursion for which its UVLS Program was designed to operate. The assessment determines whether the UVLS equipment operated according to the design of the program, which will include the operation or non-operation of any UVLS equipment within the program.

The following addresses the timing between the proposed PRC-004-5 and PRC-010-2.

For an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, it is acceptable for an applicable entity under the proposed PRC-004-5 to begin reviewing the operation. If the entity determines a Misoperation occurred, it may develop a Corrective Action Plan (CAP). Developing the CAP and correcting the Misoperation could occur in advance of the assessment conducted by the Planning Coordinator (PC) or Transmission Planner (TP) under the proposed PRC-010-2. The drafting team would anticipate the applicable entity under PRC-004 to communicate their findings; therefore, the PC or TP would account for the findings during the post event assessment.

The drafting team does not believe adding the Example #2 (Page 18 of 33) to the proposed PRC-004-5 add any benefit because there are similar examples regarding the CAP.

Hydro One Networks
Paul Malozewski
Oshani Pathirane



Hydro One supports the following comment already submitted by the TFSP: " the addition to the Facilities Section, bullet 4.2.3 "Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements" does not appear to be necessary. The BES definition excludes elements that serve radial load. UVLS schemes are normally intended to trip loads which are supplied by circuits (feeders). These circuits (feeders) would not normally be included in the BES definition. It may be helpful for the draft team to include an example in the application guideline to provide greater clarity".

Response: With regard to the comment about radial lines, the applicability in the proposed PRC-004-5 addresses the potential for the existence of UVLS that trip one or more BES Elements today, or in the future. For example, if a change were to occur in the BES definition, UVLS equipment would be properly addressed to avoid a gap in reliability. The drafting team believes the distinction is clear and an example is not necessary.

A: N/A

Oshani Pathirane, **On Behalf of:** Hydro One Networks, Inc., NPCC, Segments 1

Hydro One's additional comments on Project 2008-02.2.docx

- 0 - 0

Part 4.2 is specific to all devices not just BES as required under PRC-004. It puts the onus on the RC/TP to assess the success of the program if ever called upon to work. It is different than the PRC-004 requirement.

Response: Concerning the duplication of effort between the proposed PRC-004-5 and PRC-010-2, the drafting team notes that PRC-004 requires the owners of UVLS to evaluate the relay when it trips a BES interrupting device. In PRC-010, the planners evaluate the performance of the UVLS Program with consideration whether the UVLS equipment operated or did not operate in accordance with the UVLS Program design.

For an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, it is acceptable for an applicable entity under the proposed PRC-004-5 to begin reviewing the operation. If the entity determines a Misoperation occurred, it may develop a Corrective Action Plan (CAP). Developing the CAP and correcting the Misoperation could occur in advance of the assessment conducted by the Planning Coordinator (PC) or Transmission Planner (TP) under the proposed PRC-010-2. The drafting team would anticipate the applicable entity under PRC-004 to communicate their findings; therefore, the PC or TP would account for the findings during the post event assessment.

Southwest Power Pool
Charles Yeung

Question

1. Do you agree that the Misoperation identification and correction of UVLS equipment as retired by PRC-022-1, Requirements R1 and R1.5 is addressed by the proposed revisions of PRC-004-5 and PRC-010-2? If not, please provide comments and suggestions to improve clarity.

☐ Yes

X No

Comments:

1. In PRC-10, the applicable entities defines "UVLS entities" as those Transmission Owners with UVLS equipment. However, R1.2, requires PCs and TPs to consider the generator ride-through capabilities in their UVLS program studies. Generator data is needed from Generator Owners. These should be applicable entities to PRC-010 as well.

   We agree that the Misoperation identification and correction of UVLS equipment, as retired by PRC-022-1, Requirements R1 and R1.5, are addressed by the proposed revisions of PRC-004-5 and PRC-010-2. However, the addition of Part 4.2 to PRC-010-2 may create redundant efforts regarding evaluation of the proper operations and misoperations of UVLS equipment. More specifically, PRC-004-4 already requires UVLS entities (TO, GO and DP) to assess and identify whether or not misoperations were the cause of BES interrupting device(s) (which now include UVLS) operations). Through this assessment and identification process, the proper or improper operations of the UVLS equipment would have been identified and, where necessary and appropriate, corrective action plans would have been developed and implemented. The addition of Part 4.2, which requires the Planning Coordinator or Transmission Planner to evaluate the performance (i.e., operation and non-operation) of the UVLS Program, seems redundant to the efforts of the UVLS entities. Further, as the UVLS entities are the entities that actually operate, control, and maintain the UVLS

equipment, such entities would be in the best position to perform a thorough evaluation of the operation or misoperation of such equipment. The SRC, therefore, proposes that Part 4.2 in PRC-010-2 be removed or revised to remove redundancy and ensure that the most appropriate entity is performing such assessments. Should the SDT recommend that an independent review of such assessments and corrective actions occur, such could be considered in the context of Part 4.2

Response: The drafting team thanks you for your comment. Entities that experience an operation of the UVLS equipment that trip one or more BES Elements (irrespective of a voltage excursion) must address reviews in a shorter time (PRC-004). Likewise, planners will assess the performance of the UVLS Program following an event that resulted in a voltage excursion for which its UVLS Program was designed to operate. The assessment determines whether the UVLS equipment operated according to the design of the program, which will include the operation or non-operation of any UVLS equipment within the program.

The following addresses the timing between the proposed PRC-004-5 and PRC-010-2.

For an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, it is acceptable for an applicable entity under the proposed PRC-004-5 to begin reviewing the operation. If the entity determines a Misoperation occurred, it may develop a Corrective Action Plan (CAP). Developing the CAP and correcting the Misoperation could occur in advance of the assessment conducted by the Planning Coordinator (PC) or Transmission Planner (TP) under the proposed PRC-010-2. The drafting team would anticipate the applicable entity under PRC-004 to communicate their findings; therefore, the PC or TP would account for the findings during the post event assessment.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting of the standard on February 18, 2015.
3. Draft 1 of PRC-004-5 was posted for a 45-day formal comment period from February 20 – April 7, 2015 and an initial ballot in the last ten days of the comment period from March 27 – April 7, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 2 of PRC-004-5 – Protection System Misoperation Identification and Correction for a 10-day final ballot.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (*Undervoltage Load Shedding Program Performance*) during the development of PRC-010-1 (*Undervoltage Load Shedding*)

- Ensure the performance of the UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and, if necessary, mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (*Protection System Misoperation Identification and Correction*). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-5

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[2]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[3]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011

[3] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5		Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[4] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[5]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[6] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[7]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[4] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[5] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011). Pg. 3.

[6] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx). May 2014. Pg. 18 of 106.

[7] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a “Failure to Trip – During Fault” Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one “Failure to Trip – During Fault” Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation

times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

Example 8a: The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

Example 8b: The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: “In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties.” The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device

owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[8] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

[8] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

Example R1b: A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

Example R2a: Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize

that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[9]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

[9] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). Figure 15: NERC Wide Misoperations by Cause Code. Pg. 22 of 40.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation)

through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

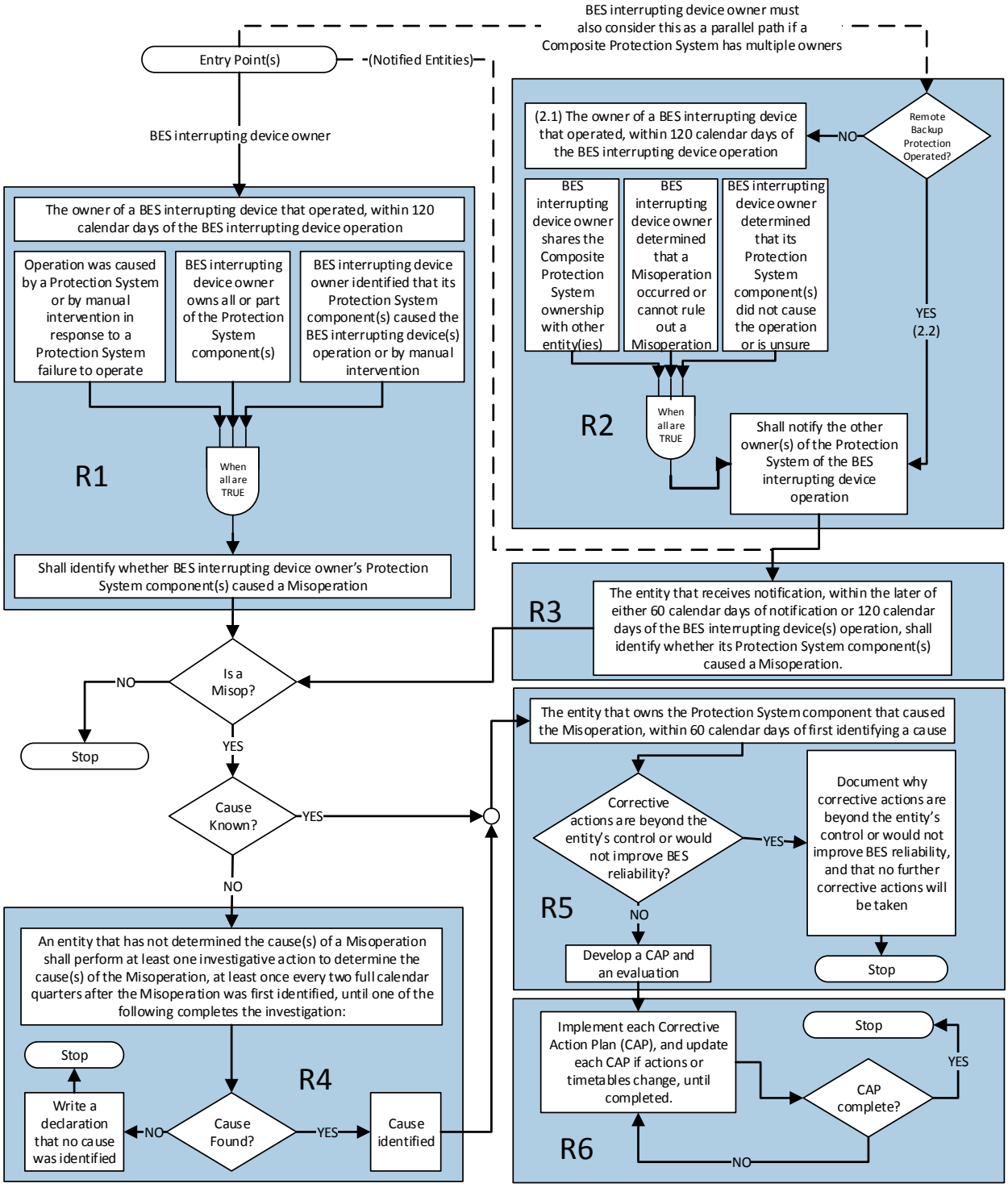
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:


BES interrupting device owner must also consider this as a parallel path if a Composite Protection System has multiple owners
Entry Point(s)
(Notified Entities)
BES interrupting device owner
The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
Operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate
BES interrupting device owner owns all or part of the Protection System component(s)
BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or by manual intervention
R1
When all are TRUE
Shall identify whether BES interrupting device owner's Protection System component(s) caused a Misoperation
Is a Misop?
NO
Stop
YES
Cause Known?
YES
NO
An entity that has not determined the cause(s) of a Misoperation shall perform at least one investigative action to determine the cause(s) of the Misoperation, at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation:
Stop
R4
Write a declaration that no cause was identified
NO
Cause Found?
YES
Cause identified
(2.1) The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
NO
Remote Backup Protection Operated?
YES (2.2)
BES interrupting device owner shares the Composite Protection System ownership with other entity(ies)
BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation
BES interrupting device owner determined that its Protection System component(s) did not cause the operation or is unsure
R2
When all are TRUE
Shall notify the other owner(s) of the Protection System of the BES interrupting device operation
R3
The entity that receives notification, within the later of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.
The entity that owns the Protection System component that caused the Misoperation, within 60 calendar days of first identifying a cause
Corrective actions are beyond the entity's control or would not improve BES reliability?
YES
Document why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken
Stop
R5
NO
Develop a CAP and an evaluation
Implement each Corrective Action Plan (CAP), and update each CAP if actions or timetables change, until completed.
Stop
CAP complete?
YES
NO
R6

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction

The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

Rationale for Applicability

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November ~~12~~13, 2014.
2. The NERC Standards Committee authorized the initial posting of the standard on February 18, 2015.
3. Draft 1 of PRC-004-5 was posted for a 45-day formal comment period from February 20 – April 7, 2015 and an initial ballot in the last ten days of the comment period from March 27 – April 7, 2015.

Description of Current Draft

The UVLSSDT is posting Draft ~~1~~2 of PRC-004-5 – Protection System Misoperation Identification and Correction for a ~~45~~10-day ~~initial formal comment period and concurrent/parallel initial~~final ballot ~~in the last ten days of the comment period. The draft contains revisions to the Applicability section to address UVLS equipment~~.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (*Undervoltage Load Shedding Program Performance*) during the development of PRC-010-1 (*Undervoltage Load Shedding*)
- Ensure the performance of the UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and, if necessary, mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (*Protection System Misoperation Identification and Correction*). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term "Misoperation" as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx~~(http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx))~~ and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx~~(http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx),~~), Introduction in the Guidelines and Technical Basis, last paragraph.

following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element ~~under~~ is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-5

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[2]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[3]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011

[3] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5		Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[4] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[5]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[6] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[7]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[4] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).

[5] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011-). Pg. 3.

[6] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx-). May 2014. Pg. 18 of 106.

[7] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation

times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

Example 8a: The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

Example 8b: The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device

owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[8] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

[8] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf.). April 1, 2013. pgPg. 37 of 40.

Example R1b: A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

Example R2a: Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize

that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[9]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

[9] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf~~:~~.). Figure 15: NERC Wide Misoperations by Cause Code. ~~pg~~Pg. 22 of 40.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation)

through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

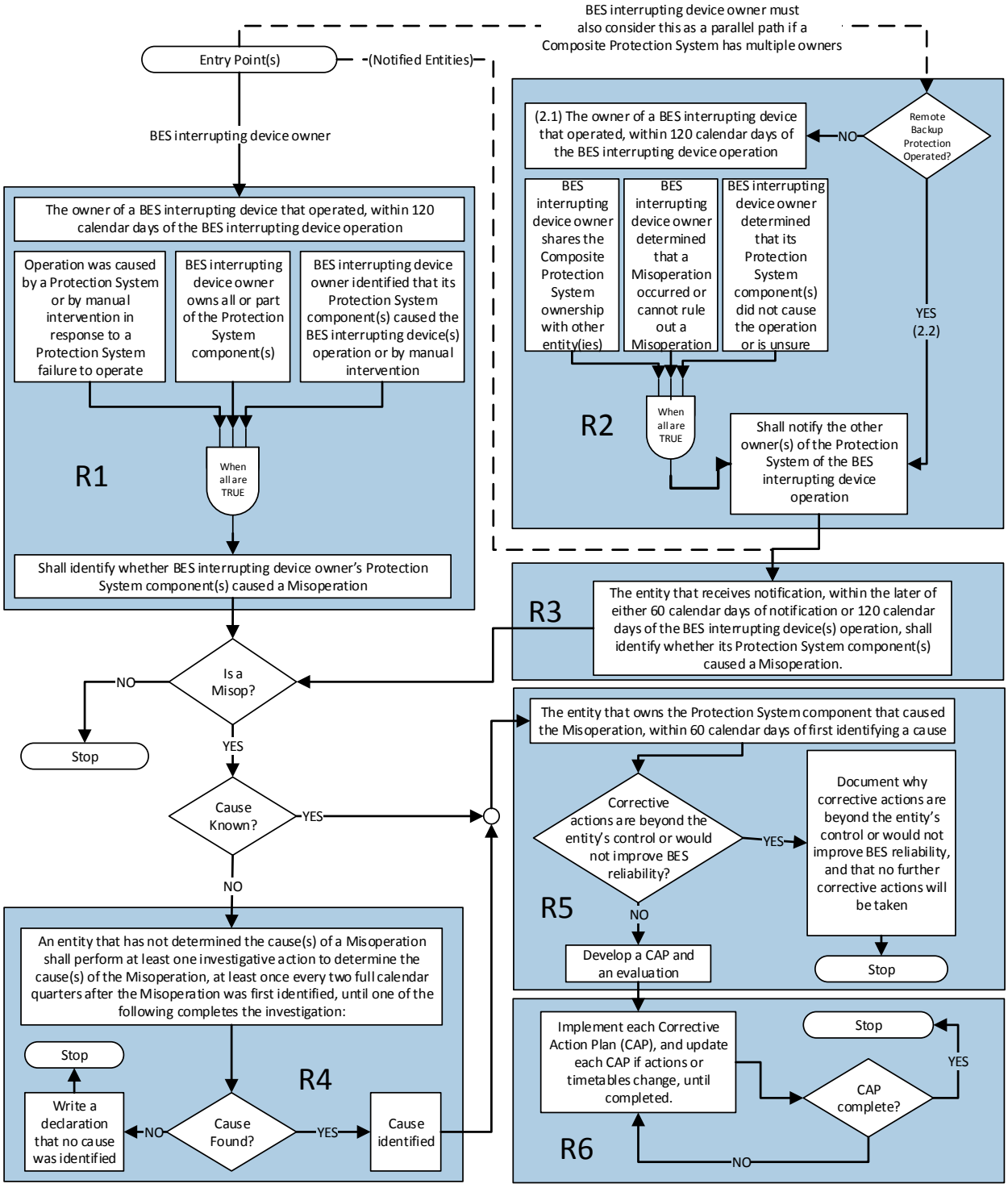
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:


BES interrupting device owner must also consider this as a parallel path if a Composite Protection System has multiple owners
Entry Point(s)
(Notified Entities)
BES interrupting device owner
The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
Operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate
BES interrupting device owner owns all or part of the Protection System component(s)
BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or by manual intervention
R1
When all are TRUE
Shall identify whether BES interrupting device owner's Protection System component(s) caused a Misoperation
Is a Misop?
NO
Stop
YES
Cause Known?
YES
NO
An entity that has not determined the cause(s) of a Misoperation shall perform at least one investigative action to determine the cause(s) of the Misoperation, at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation:
Stop
R4
Write a declaration that no cause was identified
NO
Cause Found?
YES
Cause identified
(2.1) The owner of a BES interrupting device that operated, within 120 calendar days of the BES interrupting device operation
NO
Remote Backup Protection Operated?
YES (2.2)
BES interrupting device owner shares the Composite Protection System ownership with other entity(ies)
BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation
BES interrupting device owner determined that its Protection System component(s) did not cause the operation or is unsure
R2
When all are TRUE
Shall notify the other owner(s) of the Protection System of the BES interrupting device operation
R3
The entity that receives notification, within the later of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.
The entity that owns the Protection System component that caused the Misoperation, within 60 calendar days of first identifying a cause
Corrective actions are beyond the entity's control or would not improve BES reliability?
YES
Document why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken
Stop
R5
NO
Develop a CAP and an evaluation
Implement each Corrective Action Plan (CAP), and update each CAP if actions or timetables change, until completed.
Stop
CAP complete?
YES
NO
R6

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction

The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

Rationale for Applicability

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 12, 2014.
2. NERC Standards Committee approved initial posting of the standard on February 18, 2015

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-004-5 – Protection System Misoperation Identification and Correction for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to the Applicability section to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (*Undervoltage Load Shedding Program Performance*) during the development of PRC-010-1 (*Undervoltage Load Shedding*)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (*Protection System Misoperation Identification and Correction*). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term "Misoperation" as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-45

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[2]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Dates:Date:** See theProject 2008-02.2 Implementation Plan for this Standard..

5. **Background:**

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).

- ~~Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.~~

~~Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.~~

~~The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.~~

~~Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.~~

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[3]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
~~2~~		~~Modified to address Order No. 693 Directives contained in paragraph 1469.~~	~~Revised~~
~~2~~	~~August 5, 2010~~	~~Adopted by NERC Board of Trustees~~	

[3] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Version	Date	Action	Change Tracking
1a	February 17, 2011	Adopted by NERC Board of Trustees~~Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers~~	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
~~1a~~	~~February 17, 2011~~	~~Adopted by NERC Board of Trustees~~	
1a	September 26, 2011	Appended FERC ~~Order issued approving the~~ approved interpretation of R1 and R3 ~~(FERC's Order is effective as of September 26, 2011)~~to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	~~Errata change: Edited R2 to add "…and generator interconnection Facility…"~~Adopted by NERC Board of Trustees	~~Revision~~Errata change under Project 2010-07 to add "…and generator interconnection Facility…"

Version	Date	Action	Change Tracking
~~2.1a~~	~~February 9, 2012~~	~~Errata change adopted by NERC Board of Trustees~~	
~~2.1a~~	~~September 19, 2013~~	~~FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).~~	
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	~~**Standad i**~~ Applicability ~~revised~~revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources~~. n November 13, 2014 Project 2014-01~~
5		Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[4] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[5]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[6] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[7]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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4 http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

5 "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

6 "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

7 "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** *– A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.
>
> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated

authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[8] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

[8] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.
>
> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a

Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that

certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[9]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an*

[9] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.
>
> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

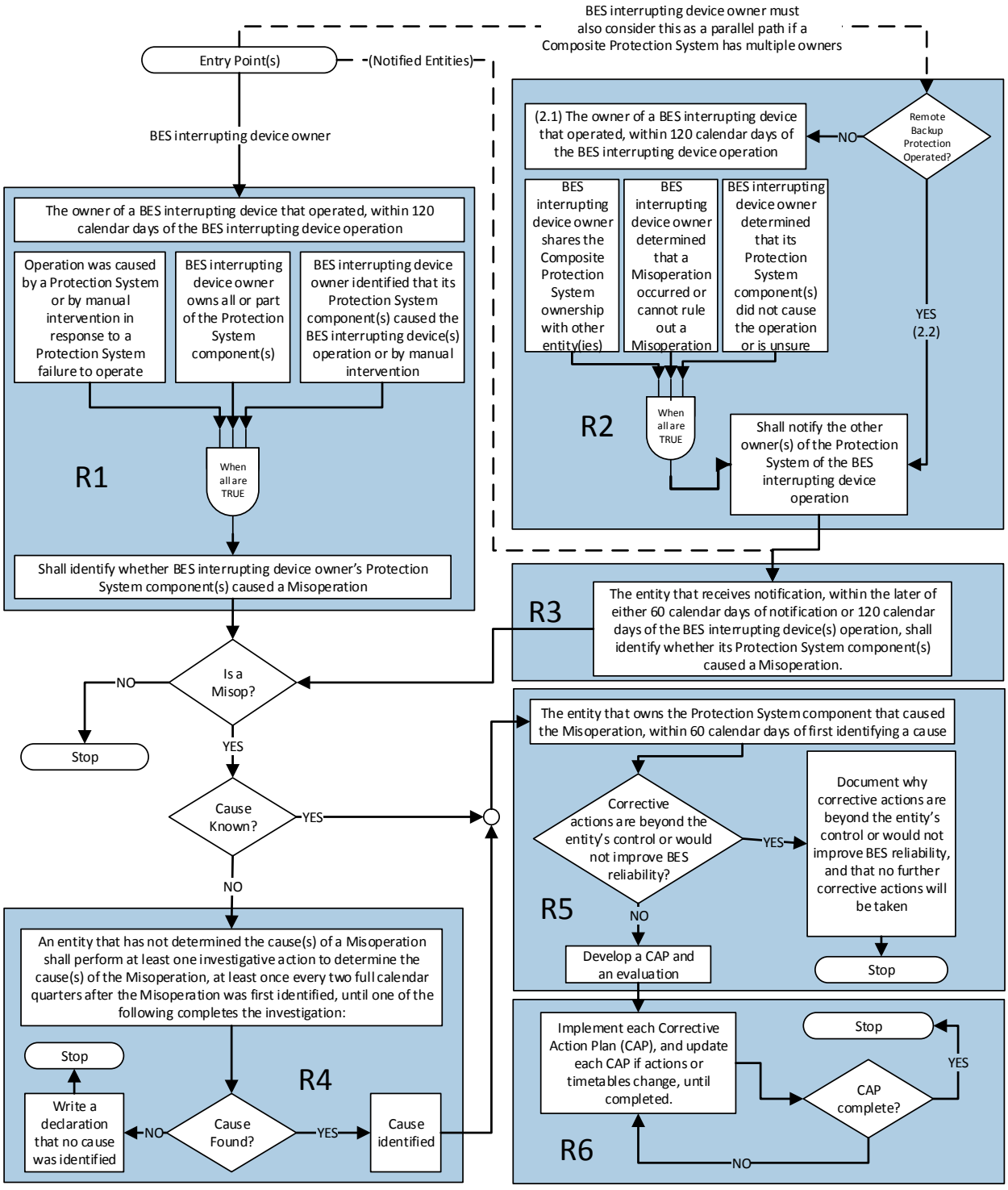
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction:

The only revisions made to this version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

The DGR version of this standard had been labeled PRC-004-4 for balloting purposes. The 'X' had indicated that a version number would be applied at a later time, because multiple versions of PRC-004 were in development at the time of the previous posting. The 'X' designation reflected the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. However, PRC-004-3 was approved by the NERC Board of Trustees on August 14, 2014, so this version has been designated PRC-004-4 to indicate that this version is the successor version.

Rationale for Applicability:

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for "common- mode failure" type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

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Implementation Plan

PRC-004-5 – Protection System Misoperation Identification and Correction

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-004-5 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-004-4 – Protection System Misoperation Identification and Correction[1]

Prerequisite Approvals

- PRC-010-2 – Undervoltage Load Shedding

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occurring soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004-5. The standard PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version two of PRC-010 is including undervoltage load shedding (UVLS) that is included in a UVLS Program.

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

[1] PRC-004-4 was adopted by the NERC Board of Trustees on November 13, 2014. PRC-004-4 is pending adoption or approval by applicable governmental authorities. PRC-004-5 will retire PRC-004-3 if PRC-004-4 is not adopted or approved by an applicable governmental authority.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-004-5 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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Implementation Plan

PRC-004-5 – Protection System Misoperation Identification and Correction

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-004-5 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-004-4 – Protection System Misoperation Identification and Correction[1]

Prerequisite Approvals

- PRC-010-2 – Undervoltage Load Shedding

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occurring soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004-5. The standard PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version two of PRC-010 is including undervoltage load shedding (UVLS) that is included in a UVLS Program.

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

[1] PRC-004-4 was adopted by the NERC Board of Trustees on November 13, 2014. PRC-004-4 is pending adoption or approval by applicable governmental authorities. PRC-004-5 will retire PRC-004-3 if PRC-004-4 is not adopted or approved by an applicable governmental authority.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-004-5 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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Implementation Plan

PRC-004-5 – Protection System Misoperation Identification and Correction

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-004-5 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-004-4 – Protection System Misoperation Identification and Correction[1]

Prerequisite Approvals

- PRC-010-2 – Undervoltage Load Shedding

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occurring soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004~~.~~ 5. The standard PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version ~~five~~two of PRC-~~004~~010 is including undervoltage load shedding (UVLS) that is ~~intended to trip one or more BES Elements~~included in a UVLS Program.

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

[1] PRC-004-4 was adopted by the NERC Board of Trustees on November 13, 2014. PRC-004-4 is pending adoption or approval by applicable governmental authorities. PRC-004-5 will retire PRC-004-3 if PRC-004-4 is not adopted or approved by an applicable governmental authority.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting of the standard on February 18, 2015.
3. Draft 1 of PRC-010-2 was posted for a 45-day formal comment period from February 20 – April 7, 2015 and an initial ballot in the last ten days of the comment period from March 27 – April 7, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 2 of PRC-010-2 – Undervoltage Load Shedding for a 10-day final ballot.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (Undervoltage Load Shedding Program Performance) during the development of PRC-010-1 (Undervoltage Load Shedding)

- Ensure the performance of the UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and, if necessary, mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (Protection System Misoperation Identification and Correction). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the Glossary of Terms Used in NERC Reliability Standards is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

When this standard receives Board adoption, the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R4 will be removed.

A. Introduction

1. **Title:** Undervoltage Load Shedding
2. **Number:** PRC-010-2
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated

with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

Rationale for Requirement R4: Refer to the Supplemental Section at the end of the document for the rationale.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three

calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances

where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2		Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

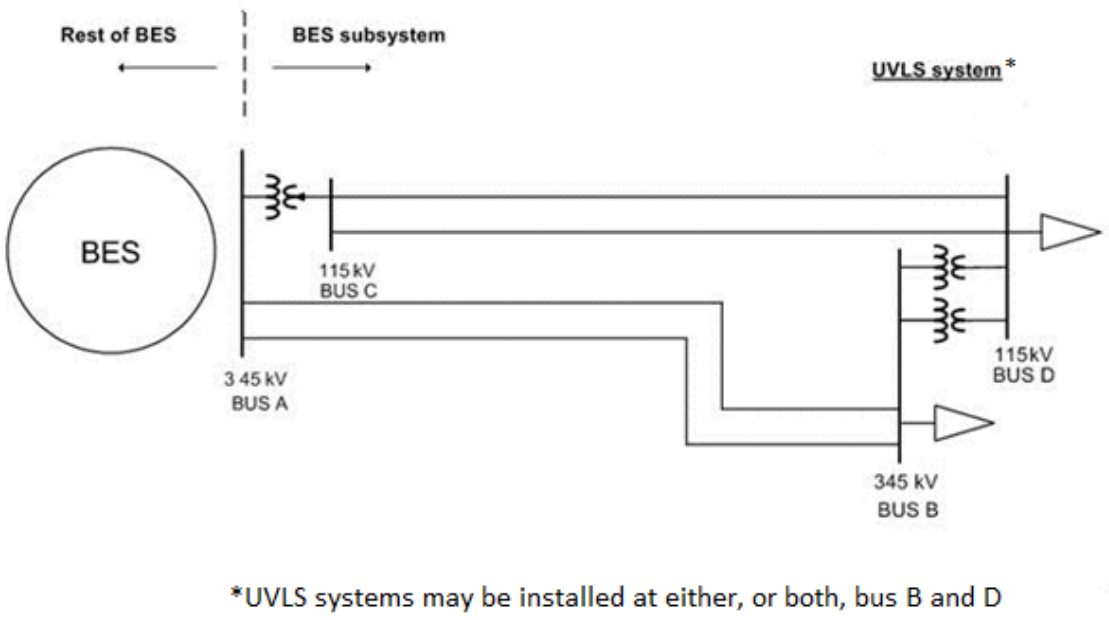


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system

performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[2] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

[2] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[3] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are

[3] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[4]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three

[4] Id.

calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well- accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the

directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential

solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[5,6] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[7] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[8] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[9] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[10] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[11] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for

[5] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding).
[6] Adopted by the NERC Board of Trustees on November 14, 2014.
[7] (http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx).
[8] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).
[9] (http://www.nerc.com/docs/docs/ferc/order_693.pdf).
[10] (http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf).
[11] (http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf).

assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[12]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[13] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[14] EOP-002-3 (Capacity and Energy Emergencies),[15] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2

[12] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[13] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans).
[14] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning).
[15] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies).

requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[16] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[17] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

[16] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations).
[17] (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[18] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

[18] Adopted by the NERC Board of Trustees on November 14, 2014.

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[19] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner

[19] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS

threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[20] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[20] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis).

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[21]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[22,23] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

[21] Refer to Standards Independent Expert Review Project (IERP). (http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf).
[22] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding).
[23] Adopted by the NERC Board of Trustees on November 14, 2014.

Effective Dates

PRC-004-5 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting of the standard on February 18, 2015.
3. Draft 1 of PRC-010-2 was posted for a 45-day formal comment period from February 20 – April 7, 2015 and an initial ballot in the last ten days of the comment period from March 27 – April 7, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 2 of PRC-010-2 – Undervoltage Load Shedding for a 10-day final ballot.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (Undervoltage Load Shedding Program Performance) during the development of PRC-010-1 (Undervoltage Load Shedding)

- Ensure the performance of the UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and, if necessary, mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (Protection System Misoperation Identification and Correction). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the Glossary of Terms Used in NERC Reliability Standards is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

When this standard receives Board adoption, the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R4 will be removed.

A. Introduction

1. **Title:** Undervoltage Load Shedding
2. **Number:** PRC-010-2
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated

with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

Rationale for Requirement R4: Refer to the Supplemental Section at the end of the document for the rationale.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three

calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances

where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2		Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

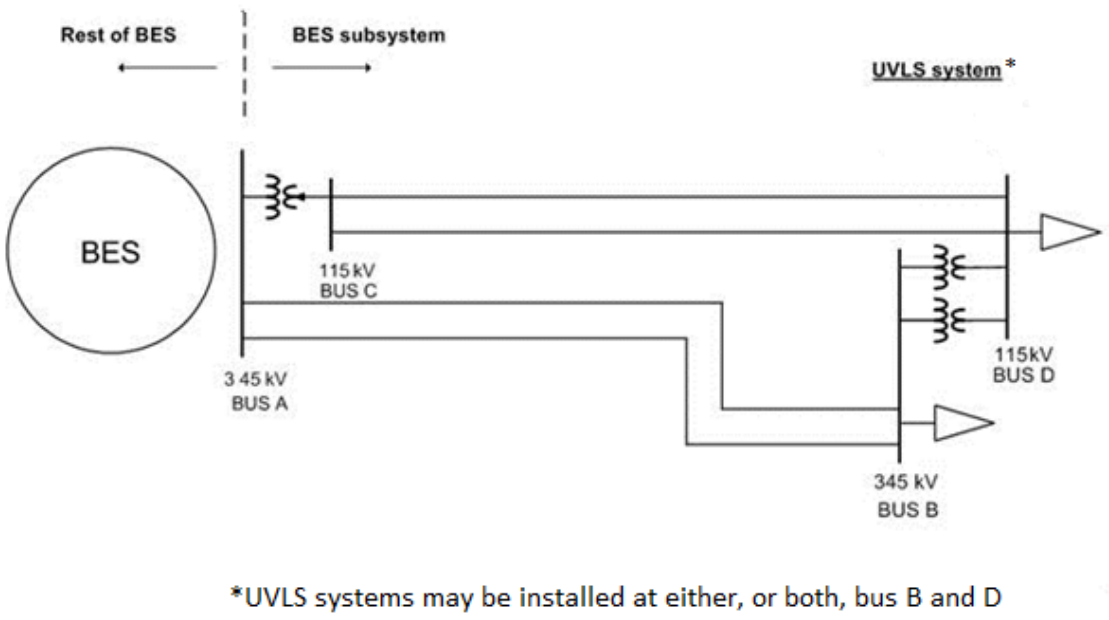


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system

performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[2] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

[2] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[3] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are

[3] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[4]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three

[4] Id.

calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well- accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the

directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential

solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[5,6] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[7] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[8] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[9] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[10] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[11] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for

[5] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding).
[6] Adopted by the NERC Board of Trustees on November 14, 2014.
[7] (http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx).
[8] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).
[9] (http://www.nerc.com/docs/docs/ferc/order_693.pdf).
[10] (http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf).
[11] (http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf).

assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[12]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[13] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[14] EOP-002-3 (Capacity and Energy Emergencies),[15] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2

[12] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[13] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans).
[14] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning).
[15] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies).

requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[16] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[17] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

[16] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations).
[17] (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[18] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

[18] Adopted by the NERC Board of Trustees on November 14, 2014.

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[19] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner

[19] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS

threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[20] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[20] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis).

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[21]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[22,23] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

[21] Refer to Standards Independent Expert Review Project (IERP). (http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf).
[22] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding).
[23] Adopted by the NERC Board of Trustees on November 14, 2014.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting of the standard on February 18, 2015.
3. Draft 1 of PRC-010-2 was posted for a 45-day formal comment period from February 20 – April 7, 2015 and an initial ballot in the last ten days of the comment period from March 27 – April 7, 2015.

Description of Current Draft

The UVLSSDT is posting Draft ~~1~~2 of PRC-010-2 – Undervoltage Load Shedding for a ~~45~~10-day ~~initial formal comment period and concurrent/parallel initial~~final ballot ~~in the last ten days of the comment period. The draft contains revisions to Requirements R4 and R5 to address UVLS equipment~~.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1

(Undervoltage Load Shedding Program Performance) during the development of PRC-010-1 (Undervoltage Load Shedding)

- Ensure the performance of the UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and, if necessary, mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (Protection System Misoperation Identification and Correction). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the Glossary of Terms Used in NERC Reliability Standards is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element ~~under~~ is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

When this standard receives Board adoption, the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement ~~R5~~R4 will be removed.

A. Introduction

1. **Title:** Undervoltage Load Shedding

2. **Number:** PRC-010-2

3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated

with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

Rationale for Requirement R4: Refer to the Supplemental Section at the end of the document for the rationale.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three

calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances

where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes~~:~~

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2		Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, "Undervoltage Load Shedding Program" or "UVLS Program" includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

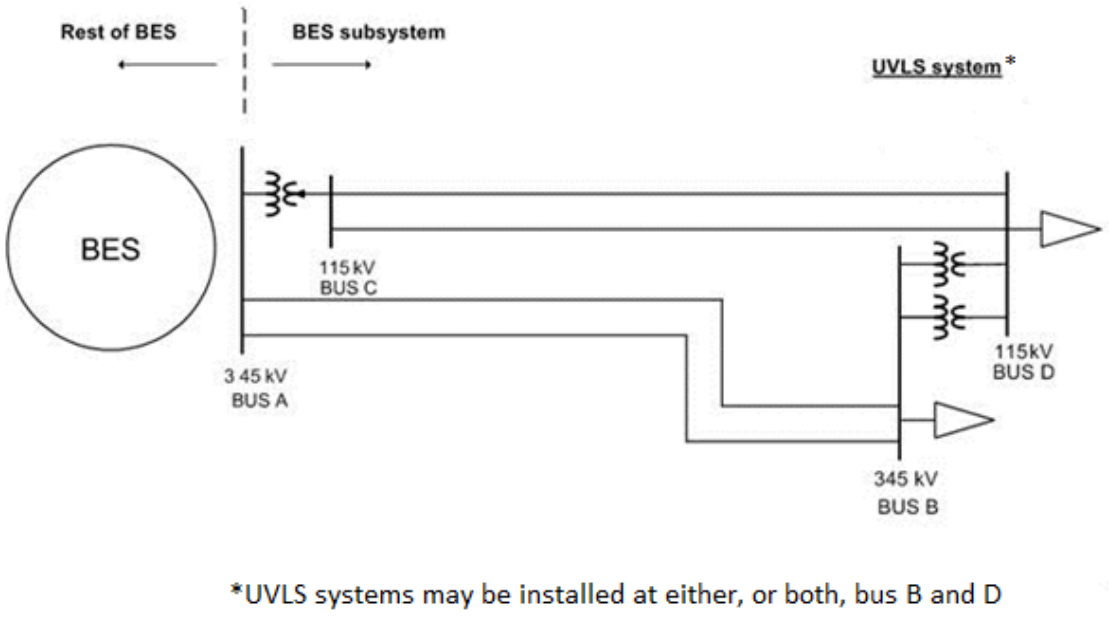


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system

performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[2] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

[2] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[3] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are

[3] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[4]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5~~:~~

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three

[4] Id.

calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well- accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the

directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential

solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[5,6] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[7] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[8] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[9] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[10] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[11] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS

[5] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding-).

[6] Adopted by the NERC Board of Trustees on November 14, 2014.

[7] (http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx).

[8] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).

[9] (http://www.nerc.com/docs/docs/ferc/order_693.pdf-).

[10] (http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf-).

[11] (http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf-).

program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[12]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[13] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[14] EOP-002-3 (Capacity and Energy

[12] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.

[13] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans-).

[14] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning-).

Emergencies),[15] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[16] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[17] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition ~~is meant to inherently exclude~~excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

[15] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies~~.~~).

[16] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations~~.~~).

[17] (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf~~.~~).

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[18] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage

[18] Adopted by the NERC Board of Trustees on November 14, 2014.

instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[19] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and

[19] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS

Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[20] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[20] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis-).

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[21]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[22,23] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

[21] Refer to Standards Independent Expert Review Project (IERP). (http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf~~.~~).

[22] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding~~.~~).

[23] Adopted by the NERC Board of Trustees on November 14, 2014.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees adopted PRC-010-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting on February 18, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-010-2 – Undervoltage Load Shedding for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to Requirements R4 and R5 to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (Undervoltage Load Shedding Program Performance) during the development of PRC-010-1 (Undervoltage Load Shedding)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (Protection System Misoperation Identification and Correction). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment. Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the Glossary of Terms Used in NERC Reliability Standards is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

When this standard receives Board adoption, the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R5 will be removed.

A. Introduction

1. **Title:** Undervoltage Load Shedding

2. **Number:** PRC-010-~~1~~-2

3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

~~1. Background:~~

~~PRC-010-1 – Undervoltage Load Shedding is a consolidation and revision of the following Reliability Standards:~~

- ~~PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program~~
- ~~PRC-020-1 – Under-Voltage Load Shedding Program Database~~
- ~~PRC-021-1 – Under-Voltage Load Shedding Program Data~~
- ~~PRC-022-1 – Under-Voltage Load Shedding Program Performance~~

~~The UVLS Standard Drafting Team (or drafting team) developed the revised PRC-010-1 to meet the following objectives:~~

- ~~Address the FERC directive in Order No. 693, Paragraph 1509 to modify PRC-010-0 to require an integrated and coordinated approach to all protection systems.~~
- ~~Replace the applicability to and involvement of the Regional Reliability Organization (RRO) in PRC-020-1 and PRC-021-1.~~
- ~~Consolidate the UVLS-related standards into one comprehensive standard (similar to the construct of FERC-approved PRC-006-1 – Automatic~~

~~Underfrequency Load Shedding).~~

- ~~Clearly identify and separate centrally controlled undervoltage□based load shedding due to the reliability requirements needed for this type of load shedding as compared to other UVLS systems.~~
- ~~Create a single results□based standard that addresses current reliability issues associated with UVLS.~~

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including,

but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

Rationale for Requirement R4: Refer to the Supplemental Section at the end of the document for the rationale.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate ~~whether its UVLS Program resolved the undervoltage issues associated with the event.~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies ~~in its UVLS Program~~ during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2		Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

~~PRC-010-1 is a single, comprehensive standard that addresses the same reliability principles outlined in its legacy standards, PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The standard also addresses a FERC directive from Order No. 693, Paragraph 1509. This paragraph directs NERC to develop a modification to PRC-010-0 that requires an integrated and coordinated approach to all protection systems, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency load shedding (UFLS) and UVLS programs.~~

~~Since FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding was developed under a similar construct of combining existing standards and addressing a FERC Order No. 693 directive, the drafting team looked to this standard as a guide. With the understanding that UVLS and UFLS systems have fundamental differences, the drafting team adopted PRC-006-1's industry-vetted reliability principles and language as applicable to UVLS Programs.~~

~~The drafting team's established purpose for PRC-010-1 is to clearly define the responsibilities of applicable entities to pursue an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS Programs. Since the need for and design of UVLS Programs is unique to each system preservation footprint, the intent of the standard is to provide a framework of reliability requirements for such programs to which each individual entity can apply its program's specific considerations and characteristics. The drafting team emphasizes that PRC-010-1 does not require a mandatory UVLS Program, nor does this standard address the need to have a UVLS Program. PRC-010-1 applies only after an entity has determined the need for a UVLS Program as a result of its own planning studies.~~

~~The~~The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

~~The design and characteristics of a centrally controlled undervoltage-based load shedding system are commensurate with a Special Protection System (SPS) or Remedial Action Scheme (RAS), therefore, the drafting team maintains that this type of load shedding should be covered by SPS or RAS-related Reliability Standards. Therefore, PRC-010-1 introduces a new Glossary of Terms Used in NERC Reliability Standards term, UVLS Program, to establish the applicability of PRC-010-1 to automatic load shedding programs consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Undervoltage-based load shedding that does not have such an impact as determined by the Planning Coordinator or Transmission Planner is not included. It is further noted that this term excludes centrally controlled undervoltage-based load shedding.~~

~~Subsequently, since the current Glossary of Terms Used in NERC Reliability Standards definition of Special Protection System excludes UVLS, concurrent Project 2010□05.2 – Special Protection Systems (Phase 2 of Protection Systems) will adjust the definition to exclude only UVLS Programs as defined above and therefore include centrally controlled undervoltage□based load shedding. Of note, the drafting team for Project 2010□05.2 is proposing to change the term from Special Protection System to Remedial Action Scheme. Accordingly, PRC□010□1 uses the term Remedial Action Scheme instead of Special Protection System. In the current inventory of NERC Reliability Standards, there is one instance of the term undervoltage load shedding program, which is in NUC□001□2.1. Project 2012□13 Nuclear Plant Interface Coordination has adjusted the language of this reference in proposed NUC□001□3 to eliminate any potential confusion of a lowercase usage of a defined term. Likewise, future projects containing standards that feature variations of the term (e.g., undervoltage load shedding system) will also be advised to consider the newly defined term.~~

~~Requirements of the revised Reliability Standard PRC□010□1 meet the following objectives:~~

- ~~Evaluate a UVLS Program's effectiveness prior to implementation, including the program's coordination with other protection systems and generator voltage ride-through capabilities.~~
- ~~Adhere to UVLS Program specifications and implementation schedule.~~
- ~~Perform periodic assessment and performance analysis of UVLS Programs and resolve identified deficiencies.~~
- ~~Maintain and share UVLS Program data.~~

~~Also of note, Project 2009□03 – Emergency Operations is proposing EOP□011□1, which, as part of the overall revisions, retires specific requirements from EOP□003□2 – Load Shedding Plans to eliminate identified redundancy between PRC□010□1 and EOP□003□2. In addition, the UVLS drafting team's intention is for PRC□004 to address Misoperations of UVLS Programs that are intended to trip one or more BES Elements. A change to make these types of UVLS Programs explicitly applicable to PRC□004 will be addressed once PRC□004□3 – Protection System Misoperation Identification and Correction is completed under Project 2010□05.1 – Misoperations (Phase 1 of Protection Systems).~~

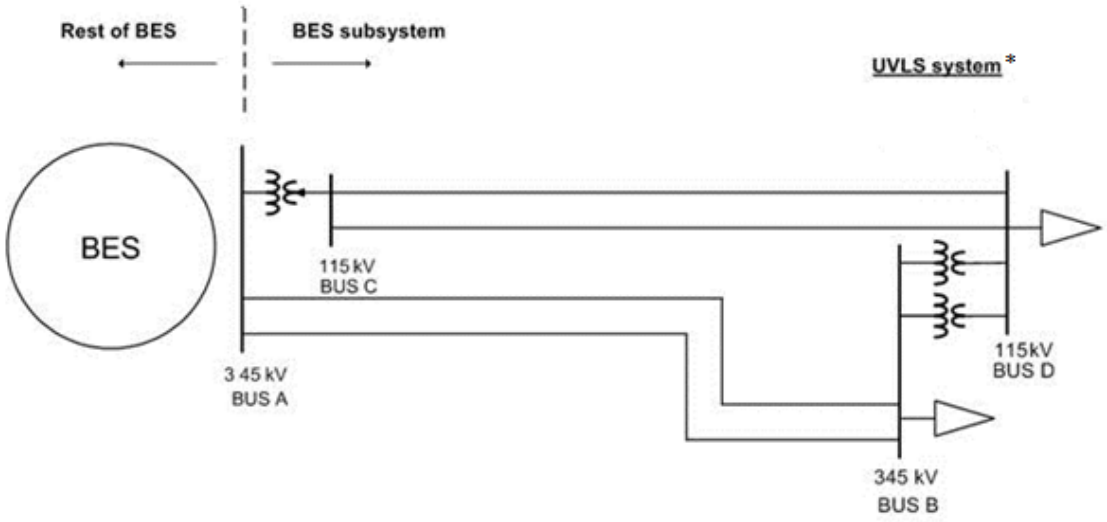
Guidelines for UVLS Program Definition

The definition for the term~~-~~, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The ~~definition for the term~~ UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS~~,~~), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard ~~is to~~includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the ~~BES.~~Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

~~Below~~Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between ~~bus~~buses A and ~~bus~~ B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading ~~involving the BES.~~, a UVLS system (installed at either, or both, bus B and D) used to mitigate this ~~case~~Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system ~~would be~~is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.



*UVLS systems may be installed at either, or both, bus B and D

~~High Level Requirement Overview~~

~~Requirement~~

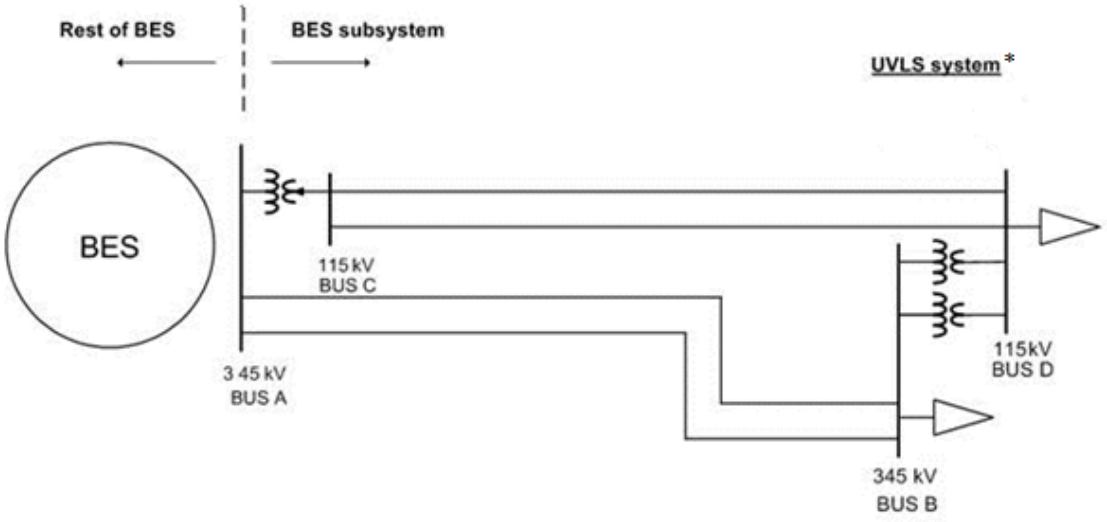


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1~~:~~

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static ~~var~~voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

~~Examples~~The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2~~:~~

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed~~, etc~~. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

> **CAP Example 1** - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the ~~misoperation~~Misoperation[1] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3~~:~~

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment ~~should~~is required to be completed at least once every 60 calendar months to capture the accumulated

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment supplementscomplements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

With respect to situations in which a material change to system and topology or operating conditions would necessitate a comprehensive assessment of the UVLS Program, it is understood that the term material change is not transportable on a continent□wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4:

TheAfter a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues for an event that occurred on the system. It is expected that, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event shall beis performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.
[3] Id.

effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12- calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC- 006-1.

Guidelines for Requirement R5:

Requirement R5 promotes the prudent correction of an identified problem during the assessment ~~evaluations~~ of ~~each~~a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate~~.~~
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated~~.~~

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, ~~the drafting team believes that within~~ three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three calendar months” time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP’s associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop ~~remedial action plans~~Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted

- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS~~,~~), and RAS~~.~~

Additionally, the UVLS Program database ~~should~~is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well-accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~

0	February 8, 2005	Adopted by NERC Board of Trustees	
0	March 16, 2007	Approved by FERC	
0	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
1.0	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Completed revision, merged and updated PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program

according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment ~~of a UVLS Program~~ performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. -Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

[4] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding.
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project 2010-05_Protection_System_Misoperations.aspx).
[8] http://www.nerc.com/docs/docs/ferc/order_693.pdf.
[9] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by

[10] http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf.
[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[12] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans.

Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition is meant to inherently exclude locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

[13] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning.
[14] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies.
[15] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations.
[16] http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion)

to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

[19] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis.
[20] Refer to Standards Independent Expert Review Project (IERP). http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf.
[21] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding.
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

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Implementation Plan

PRC-010-2 – Undervoltage Load Shedding

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-010-2 – Undervoltage Load Shedding

Requested Retirements

- PRC-010-1 – Undervoltage Load Shedding[1]

Prerequisite Approvals

- PRC-004-5 — Protection System Misoperation Identification and Correction

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occur soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-010-2. PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version five of PRC-004 is including undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Applicable Entities

- Planning Coordinator
- Transmission Planner
- Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator

Effective Dates

PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

[1] PRC-010-1 was adopted by the NERC Board of Trustees on November 13, 2014.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

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Implementation Plan

PRC-010-2 – Undervoltage Load Shedding

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-010-2 – Undervoltage Load Shedding

Requested Retirements

- PRC-010-1 – Undervoltage Load Shedding[1]

Prerequisite Approvals

- PRC-004-5 — Protection System Misoperation Identification and Correction

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occur soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-~~004~~010-2. PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version five of PRC-004 is including undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Applicable Entities

- Planning Coordinator
- Transmission Planner
- Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator

Effective Dates

PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

[1] PRC-010-1 was adopted by the NERC Board of Trustees on November 13, 2014.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

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Mapping Document

Project 2008-02.2 Phase 2: Undervoltage Load Shedding

During development of PRC-010-1, the standard drafting team provided the following explanation on its approach to cover Misoperation of UVLS equipment in future work:

> "As PRC-022-1 addresses UVLS equipment Misoperations, the UVLS drafting team's intention is for PRC-004 to address Misoperations of UVLS Program equipment. A change to make PRC-004 explicitly applicable to UVLS Program equipment will be addressed once PRC-004-3 – Protection System Misoperation Identification and Correction[1] is completed under Project 2010-05.1 – Misoperations (Phase 1 of Protection Systems)."

The table below demonstrates how proposed changes map from the retirement of PRC-022-1 (retired by the initial 2008-02 project) to the proposed PRC-010-2. The revisions are being proposed to provide additional clarity with the aligning revisions being proposed in PRC-004-5 as shown in Table 2.

[1] PRC-004-3 was surpassed by version four which addressed applicability to dispersed generation resources under Project 2014-01.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	PRC-010-2 proposes Part 4.2 to provide additional clarity that UVLS equipment operations and Misoperations are addressed by Requirement R4 through the Planning Coordinator or Transmission Planner assessment. Part 4.1 was originally embedded in the main Requirement R4 of PRC-010-1 and is now shown as a new Part 4.1 now. Part 4.2 is being proposed to provide the necessary clarity that the assessment conducted following an event that resulted in a voltage excursion for which its UVLS Program was designed to operate must include UVLS Program equipment.	**R4.** Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: **4.1.** whether its UVLS Program resolved the undervoltage issues associated with the event, and **(Proposed) 4.2.** the performance (i.e., operation and non-operation) of the UVLS Program equipment.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
	Part 4.2 requires the Planning Coordinator or Transmission Planner to assess the UVLS equipment performance and address any deficiencies in a Corrective Action Plan (CAP) as required by PRC-010-2, Requirement R5. The clause "in its UVLS Program" was removed to clarify the Corrective Action Plan is addressing components of the assessment, which is about the UVLS Program.	**R5.** Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment.

Table 2: Mapping PRC-022-1 to PRC-004-5		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-5 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	The proposed Applicability 4.2.3 addresses the clause "analyze and document all UVLS operations and Misoperations" in PRC-022-1, Requirement R1. The standard PRC-004-5, Requirement R5 requires a Corrective Action Plan (CAP) to be developed for a known cause of a Misoperation and addresses Requirement R1.5. Requirement R6 requires the implementation of the CAP.	**(Proposed) 4.2.3** Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or

Table 2: Mapping PRC-022-1 to PRC-004-5		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-5 or Comments**
		• Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.

Mapping Document
Project 2008-02.2 Phase 2: Undervoltage Load Shedding

During development of PRC-010-1, the standard drafting team provided the following explanation on its approach to cover Misoperation of UVLS equipment in future work:

> "As PRC-022-1 addresses UVLS equipment Misoperations, the UVLS drafting team's intention is for PRC-004 to address Misoperations of UVLS Program equipment. A change to make PRC-004 explicitly applicable to UVLS Program equipment will be addressed once PRC-004-3 – Protection System Misoperation Identification and Correction[1] is completed under Project 2010-05.1 – Misoperations (Phase 1 of Protection Systems)."

~~Table~~The table below demonstrates how proposed changes map from the retirement of PRC-022-1 (retired by the initial 2008-02 project) to the proposed PRC-010-2. The revisions are being proposed to provide additional clarity with the aligning revisions being proposed in PRC-004-5 as shown in Table 2.

[1] PRC-004-3 was surpassed by version four which addressed applicability to dispersed generation resources under Project 2014-01.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	PRC-010-2 proposes Part 4.2 to provide additional clarity that UVLS equipment operations and Misoperations are addressed by Requirement R4 through the Planning Coordinator or Transmission Planner assessment. Part 4.1 was originally embedded in the main Requirement R4 of PRC-010-1 and is now shown as a new Part 4.1 now. Part 4.2 is being proposed to provide the necessary clarity that the assessment conducted following an event that resulted in a voltage excursion for which its UVLS Program was designed to operate must include UVLS Program equipment.	**R4.** Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: **4.1.** whether its UVLS Program resolved the undervoltage issues associated with the event, and **(Proposed) 4.2.** the performance (i.e., operation and non-operation) of the UVLS Program equipment.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
	Part 4.2 requires the Planning Coordinator or Transmission Planner to assess the UVLS equipment performance and address any deficiencies in a Corrective Action Plan (CAP) as required by PRC-010-2, Requirement R5. The clause "in its UVLS Program" was removed to clarify the Corrective Action Plan is addressing components of the assessment, which is about the UVLS Program.	**R5.** Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. ~~[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~

Table 2: Mapping PRC-~~022-1 to PRC-~~004-5		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-5 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	The proposed Applicability 4.2.3 addresses the clause "analyze and document all UVLS operations and Misoperations~~."~~" in PRC-022-1, Requirement R1. The standard PRC-004-5, Requirement R5 requires a Corrective Action Plan (CAP) to be developed for a known cause of a Misoperation and addresses Requirement R1.5. Requirement R6 requires the implementation of the CAP.	**(Proposed) 4.2.3** Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or

Table 2: Mapping PRC-022-1 to PRC-004-5		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-5 or Comments**
		• Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.

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Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-004-3 – Protection System Misoperation Identification and Correction.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if

violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VRF Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination

[1] *N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,145 (2007) ("VRF Order"), *order on reh'g and compliance filing*, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id.* at fn 15.

- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF Discussion

The discussion below in the tables addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a

revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations and combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1.[3] First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, it must explain this in a declaration why no further corrective actions will be taken.

In the last Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

[3] The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by an owner is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is not in itself likely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R1	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of "High." The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". The performance activity that has been isolated in Requirement R1 of PRC-004-3, to "review" (similar to "analyze"), is consistent with similar requirements in Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement comingles multiple activities
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R1	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R2	
	Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system by creating a gap in analysis.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System component(s) when it determines that (or is unsure whether)its component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the Composite Protection System owned by others. This ensures that all owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R2	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". This requirement and a VRF assignment of Medium is consistent, for example, with Reliability Standards FAC-008-3 – Facility Ratings, R7 ("…shall provide Facility Ratings (for its solely and jointly owned Facilities…"), MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 ("…shall provide appropriate equipment characteristics and system data…"), IRO-015-1 – Special Protection System Data and Documentation, R1.1 ("…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas."), and IRO-016-1 – Coordination of Real-time Activities Between Reliability Coordinators, R1 ("…shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.") which all have a VRF of Medium. Other Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 ("…shall provide documentation…"), PRC-016-0.1 – Special Protection System Misoperations, R3 ("…that owns an SPS shall provide documentation of the misoperation analyses…"), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 ("…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R2			
	Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR

VRF and VSL Justifications – PRC-004-3, R2			
			The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b:		

VRF and VSL Justifications – PRC-004-3, R2	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This Requirement R3, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.

VRF and VSL Justifications – PRC-004-3, R3			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R4	
	An Unidentified cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." This Requirement R4, to perform at least one "investigative action" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R4	
	A VRF of Medium is not inadvertently lowering the current VRF of High in the former PRC-004-2.1a, Requirements R1 or R3, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R4			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard.		

VRF and VSL Justifications – PRC-004-3, R4	
	This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future Misoperations"), PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…"), FAC-003, R5 ("…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management") all three of which have a VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5			
	An unresolved cause of a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system if the same condition resulted in a future Misoperation.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

VRF and VSL Justifications – PRC-004-3, R5			
The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. This Requirement has a Severe VSL for failure to develop the CAP with the other VSLs being based on tardiness of the development.		

VRF and VSL Justifications – PRC-004-3, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An uncorrected cause of a Misoperation as a result of not implementing a Corrective Action Plan, could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system since the condition could occur again.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2.1a, R1 (TO & DP) and R2 (GO),which both have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan”. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future misoperations.”) and PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”) which both have a VRF of Medium. The proposed VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

VRF and VSL Justification – PRC-004-3, R6	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of this Requirement that are not equal in importance and performance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justification – PRC-004-3, R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2008-02 Undervoltage Load Shedding (PRC-010-1)

VRF and VSL Justifications

This document provides the Undervoltage Load Shedding Standard Drafting Team's (drafting team's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-010-1 – Undervoltage Load Shedding.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The drafting team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures, or hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or

restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the drafting team considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The drafting team believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-010-1 – Undervoltage Load Shedding is a standard revision with the stated purpose: *To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs.* FERC Order No. 693 requested that PRC-010-0 be modified to require that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency loading shedding (UFLS) and undervoltage load shedding (UVLS) programs. PRC-010-1 addresses this directive in addition to consolidating and revising PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program with three (3) other existing UVLS standards: PRC-020-1 – Under-Voltage Load Shedding Program Database, PRC-021-1 – Under-Voltage Load Shedding Program Data, and PRC-022-1 – Under-Voltage Load Shedding Program Performance.

PRC-010-1 has eight (8) requirements that incorporate and enhance the intent of the requirements of PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The revised standard requires that entities developing an Undervoltage Load Shedding Program (UVLS Program) evaluate the program's effectiveness prior to providing the program specifications and schedule to applicable entities. Applicable entities are then required to adhere to the UVLS Program specifications and implementation schedule, including those specifications and schedules associated with Corrective Action Plans (CAPs) for existing programs. The standard also requires an assessment of a UVLS Program at least once every 60 months, and an assessment to evaluate program performance within 12 months of an applicable event. If program deficiencies are identified as a result of either of these assessments, entities are required to develop and provide a CAP to applicable entities within three (3) months. In addition, there are requirements to update, provide data for, and share a UVLS Program database containing information necessary to model the program for use in event analyses and assessments.

The requirements of PRC-010-1 do not map, one-to-one, with the requirements of the legacy standards. The new requirements comingle various reliability attributes of the legacy standards with new reliability objectives, thus a requirement-to-requirement comparison of VRFs is not always possible. In developing the new VRFs for the requirements of PRC-010-1, the drafting team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding influenced the drafting team's VRF decisions (citing FERC VRF Guideline 3), as the drafting team used PRC-006-1 as a model with respect to PRC-010-1's language and construct.

NERC Criteria - Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications – PRC-010-1 Requirement R1	
Proposed VRF	High
NERC VRF Discussion	PRC-010-1 Requirement R1 meets the NERC criterion for a High VRF. Failure to evaluate a UVLS Program to show that it resolves the undervoltage issue it was designed for, and that it is coordinated with generator voltage ride-through capabilities and other protection and control systems, could lead to implementation of an ineffective or counterproductive program. In addition, failure to subsequently provide the UVLS Program specifications and implementation schedule to applicable entities would negate proper program implementation. Both these implications could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to Bulk Electric System (BES) instability, separation, or Cascading failures.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R1 has parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R1 is similar to EOP-003-2, Requirements R3, R4, and R7, which have approved VRFs of High.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R1 meets the NERC criterion for a High VRF. Failure to evaluate a UVLS Program to show that it resolves the undervoltage issue it was designed for, and that it is coordinated with generator voltage ride-through capabilities and other protection and control systems, could lead to implementation of an ineffective or counterproductive program. In addition, failure to subsequently provide the UVLS Program specifications and implementation schedule to applicable entities would negate proper program implementation. Both these implications could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligations in PRC-010-1 Requirement R1, which are to evaluate the effectiveness of a UVLS Program according to the criteria specified in the two parts and subsequently provide the program specifications and implementation schedule to applicable entities, are all equally critical elements that failure to meet could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or

VRF and VSL Justifications – PRC-010-1 Requirement R1	
	Cascading failures. Therefore, the assigned VRF of High is consistent throughout the requirement.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in parts 1.1 and 1.2.
NERC VSL Guidelines Discussion	The proposed VSL for PRC-010-1 Requirement R1 meets NERC's VSL Guidelines in that there is a binary aspect for failure; the VSL addresses the degrees of compliance with respect to equal importance of the two parts.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** The basis for the current level of compliance in relation to PRC-010-1 Requirement R1 is EOP-003-2 Requirements R3, R4, and R7, as these requirements are being retired because they map to PRC-010-1 Requirement R1. Since the VSL for PRC-010-1 Requirement R1 is binary, the current level of compliance is met or exceeded when compared to the VSLs for EOP-003-2 Requirements R3, R4, and R7.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** The proposed VSL for PRC-010-1 Requirement R1 is binary and is consistent with the guideline in that it is classified as a severe VSL. **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSL for PRC-010-1 Requirement R1 uses the term "effectiveness" from the associated requirement, which could be considered ambiguous terminology; however, Requirement R1 does qualify the term "effectiveness" by indicating that the applicable entity must include what is listed in the requirement's parts in its evaluation of effectiveness. The VSL subsequently notes that the items specified in the parts must be included. This thereby supports uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-010-1 Requirement R1	
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSL for PRC-010-1 Requirement R1 uses similar terminology to that used in the requirement and is therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSL for PRC-010-1 Requirement R1 is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R2	
Proposed VRF	High
NERC VRF Discussion	PRC-010-1 Requirement R2 meets the NERC criterion for a High VRF. Failure to implement a UVLS Program by adhering to the program specifications and implementation schedule increases the risk that the program will not perform properly. Under anticipated Emergency, abnormal, or restorative conditions, this could directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R2 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R2 is similar to PRC-006-1 Requirement R9 and EOP-003-2 Requirement R5, which have approved VRFs of High.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R2 meets the NERC criterion for a High VRF. Failure to implement a UVLS Program by adhering to the program specifications and implementation schedule increases the risk that the program will not perform properly. Under anticipated Emergency, abnormal, or restorative conditions, this could directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligations required in PRC-010-1 Requirement R2 are to adhere to the UVLS Program specifications and implementation schedule associated with program development (per Requirement R1) and corrective action (per Requirement R5). The requirement to develop a CAP in Requirement R5 is assigned a Medium VRF; therefore, execution of the corrective actions required by Requirement R2 has a commensurate VRF of Medium. However, since the obligations related to the development of a UVLS Program in Requirement R1 are assigned a High VRF, the failure to implement the program per Requirement R2 could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures. Therefore, Requirement R2 is assigned a High VRF to reflect the higher risk level associated with the more critical objective.
Proposed Lower VSL	N/A

VRF and VSL Justifications – PRC-010-1 Requirement R2	
Proposed Moderate VSL	N/A
Proposed High VSL	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.
Proposed Severe VSL	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R2 meets NERC's VSL Guidelines in that the VSLs cover aspects of the requirement that are equal in importance.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R2 is a new requirement; therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R2 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R2 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R2 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R3	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R3 meets NERC's criterion for a Medium VRF. Failure to perform a comprehensive assessment to evaluate the effectiveness of a UVLS Program at least once every 60 calendar months could lead to failure to identify and address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly and adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to do a periodic comprehensive assessment of the program, which supplements the annual Transmission Planning (TPL) assessment required by NERC Reliability Standards, would have implications on the BES. Therefore, a violation of Requirement R3 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R3 has parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R3 is consistent with the current requirement it is replacing (PRC-010-0 Requirement R1), which has an approved VRF of Medium. Similar performance exists in PRC-006-1 Requirement R4, which has an approved VRF of High. This discrepancy is justified due to the differing nature of the programs these standards are addressing, as PRC-006-1 addresses mandatory UFLS programs and PRC-010-1 covers optional UVLS Programs. A UFLS program inherently has a more likely overall impact on the BES.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R3 meets NERC's criterion for a Medium VRF. Failure to perform a comprehensive assessment to evaluate the effectiveness of a UVLS Program at least once every 60 calendar months could lead to failure to identify and address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly and

VRF and VSL Justifications – PRC-010-1 Requirement R3	
	adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to do a periodic comprehensive assessment of the program, which supplements the annual TPL assessment required by NERC Reliability Standards, would have implications on the BES. Therefore, a violation of Requirement R3 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligation required in PRC-010-1 Requirement R3 is to periodically evaluate the effectiveness of a UVLS Program according to the criteria specified in the two parts; the parts are equally critical elements that failure to meet could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures. However, violation of these commensurate elements is unlikely to lead to BES instability, separation, or Cascading failures. Therefore, the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in parts 3.1 and 3.2.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R3 meets NERC's VSL Guidelines in that there is a binary aspect for failure; the VSL addresses the degrees of compliance with respect to equal importance of the two parts.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** The proposed VSL for PRC-010-1 Requirement R3 is consistent in nature with the VSL for the requirement it is replacing (PRC-010-0 Requirement R1) and therefore does not lower the current level of compliance.

VRF and VSL Justifications – PRC-010-1 Requirement R3	
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** The proposed VSL for PRC-010-1 Requirement R3 for this binary requirement is consistent with the guideline in that it is classified as a severe VSL. **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSL for PRC-010-1 Requirement R3 does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSL for PRC-010-1 Requirement R3 uses similar terminology to that used in the requirement and is therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSL for PRC-010-1 Requirement R3 is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R4	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R4 meets NERC's criterion for a Medium VRF. Failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event in a timely manner could lead to failure to identify and address a necessary program modification. This could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event would have implications on the BES, as these are infrequent and would be done in addition to the annual TPL assessment required by NERC Reliability Standards. Therefore, a violation of Requirement R4 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R4 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R4 is similar to PRC-022-1 Requirement 1 and PRC-006-1 Requirement R11, which have approved VRFs of Medium.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R4 meets NERC's criterion for a Medium VRF. Failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event in a timely manner could lead to failure to identify and address a necessary program modification. This could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or

VRF and VSL Justifications – PRC-010-1 Requirement R4	
	counterproductive program if the criteria is not met, it is less likely that failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event would have implications on the BES, as these are infrequent and would be done in addition to the annual TPL assessment required by NERC Reliability Standards. Therefore, a violation of Requirement R4 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R4 does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.
Proposed Moderate VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.
Proposed High VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.
Proposed Severe VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R4 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R4 is different in construct from the requirement it is replacing (PRC-022-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.

VRF and VSL Justifications – PRC-010-1 Requirement R4	
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R4 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R4 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R4 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R5 meets NERC's criterion for a Medium VRF. Failure to develop and subsequently provide a CAP to address the deficiencies identified as a result of a UVLS Program assessment in a timely manner could lead to failure to address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, since the development of a CAP in Requirement R5 is dependent on the outcomes of Requirement R3 or R4, the likelihood of implications on the BES is commensurate with those of Requirements R3 and R4, which are assigned Medium VRFs. Therefore, a violation of Requirement R5 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R5 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R5 is similar to PRC-022-1 Requirement R1.5, which has an approved VRF of Medium.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R5 meets NERC's criterion for a Medium VRF. Failure to develop and subsequently provide a CAP to address the deficiencies identified as a result of a UVLS Program assessment in a timely manner could lead to failure to address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, since the development of a CAP in Requirement R5 is dependent on the outcomes of Requirement R3 or R4, the likelihood of implications on the BES is commensurate with those of Requirements R3 and R4, which are assigned Medium VRFs. Therefore, a violation of Requirement R5 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R5 does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.
Proposed Moderate VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.
Proposed High VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.
Proposed Severe VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R5 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R5 is different in construct from the requirement it is replacing (PRC-022-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R5 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R5 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R5 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R6	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R6 meets NERC's criterion for a Lower VRF. Though having a current UVLS Program database is necessary to properly inform accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to annually update a UVLS Program database would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** The requirement has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R6 similar to PRC-006-1 Requirement R6, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R6 meets NERC's criterion for a Lower VRF. Though having a current UVLS Program database is necessary to properly inform accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to annually update a UVLS Program database would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R6 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.
Proposed Moderate VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.
Proposed High VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90

VRF and VSL Justifications – PRC-010-1 Requirement R6	
	calendar days.
Proposed Severe VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R6 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R6 is replacing PRC-020-1 Requirement R1, which is applicable to the Regional Reliability Organization and has no associated VSLs. Therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R6 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R6 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R6 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R7	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R7 meets NERC's criterion for a Lower VRF. Though providing current and formatted data is necessary to properly support a UVLS Program database, which subsequently informs accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to provide the data according to the format and schedule specified would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R7 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3 Consistency among Reliability Standards:** PRC-010-1 Requirement R7 is similar to PRC-006-1 Requirement R8, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R7 meets NERC's criterion for a Lower VRF. Though providing current and formatted data is necessary to properly support a UVLS Program database, which subsequently informs accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to provide the data according to the format and schedule specified would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R7 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR

VRF and VSL Justifications – PRC-010-1 Requirement R7	
	The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.
Proposed Moderate VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.
Proposed High VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.
Proposed Severe VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R7 meets NERC's VSL Guidelines in that the VSLs cover aspects of the requirement that are not equal in importance; there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R7 is different in construct from the requirement it is replacing (PRC-021-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R7 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R7 use similar terminology to that used in the requirement and are therefore consistent with the requirement.

VRF and VSL Justifications – PRC-010-1 Requirement R7	
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R7 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R8	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R8 meets NERC's criterion for a Lower VRF. Though sharing a UVLS Program database with applicable entities in a timely manner supports an integrated and coordinated approach to UVLS programs, this is a planning requirement that is administrative in nature; failure to share the database within 30 calendar days of a request would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** The requirement has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R8 is similar to PRC-006-1 Requirement R7, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R8 meets NERC's criterion for a Lower VRF. Though sharing a UVLS Program database with applicable entities in a timely manner supports an integrated and coordinated approach to UVLS programs, this is a planning requirement that is administrative in nature; failure to share the database within 30 calendar days of a request would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R8 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.
Proposed Moderate VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.

VRF and VSL Justifications – PRC-010-1 Requirement R8	
Proposed High VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.
Proposed Severe VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R8 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R8 is replacing PRC-020-1 Requirement R2, which is applicable to the Regional Reliability Organization and has no associated VSLs. Therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R8 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R8 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R8 are based on a single violation and not cumulative violations.

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Standards Announcement

Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations
PRC-004-5 and PRC-010-2

Final Ballot Open through April 27, 2015

Now Available

A final ballot for **PRC-004-5 – Protection System Misoperation Identification and Correction and PRC-010-2 – Under Voltage Load Shedding** is open through **8 p.m. Eastern, Monday, April 27, 2015**.

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a vote. All ballot pool members may change their previously cast votes. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard here. If you experience any difficulties in using the Standards Commenting & Balloting System, contact Arielle Cunningham.

Next Steps

The voting results for the standard will be posted and announced after the ballot closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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Standards Announcement

Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations
PRC-004-5 and PRC-010-2

Final Ballot Results

Now Available

A final ballot for **PRC-004-5 – Protection System Misoperation Identification and Correction** and **PRC-010-2 – Under Voltage Load Shedding** concluded at **8 p.m. Eastern, Monday, April 27, 2015.**

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Quorum /Approval
84.86% / 89.63%

Next Steps
The standard will be submitted to the NERC Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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BALLOT RESULTS

Ballot Name: 2008-02.2 Phase 2 UVLS PRC-004-5 & PRC-010-2 FN 2 ST
Voting Start Date: 4/17/2015 8:20:05 AM
Voting End Date: 4/27/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 241
Total Ballot Pool: 284
Quorum: 84.86
Weighted Segment Value: 89.63

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	76	1	38	0.884	5	0.116	0	22	11
Segment: 2	9	0.5	3	0.3	2	0.2	0	1	3
Segment: 3	67	1	35	0.946	2	0.054	0	18	12
Segment: 4	20	1	15	0.938	1	0.062	0	2	2
Segment: 5	60	1	34	0.895	4	0.105	0	13	9
Segment: 6	40	1	26	0.963	1	0.037	0	9	4
Segment: 7	1	0	0	0	0	0	0	0	1

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Segment: 9	2	0.1	1	0.1	0	0	0	0	1
Segment: 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	284	6.5	160	5.826	16	0.674	0	65	43

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	ATCO Electric	David Downey	Dan Bamber	Abstain	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission	Jason Snodgrass	Greg Davis	Affirmative	N/A

	Corporation				
1	Great Plains Energy - Kansas City Power and Light Co.	Daniel Gibson		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	M and A Electric Power Cooperative	William Price		Abstain	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Abstain	N/A
1	National Grid USA	Michael Jones		Negative	N/A
1	NB Power Corporation	Alan MacNaughton		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A

1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	John Walker		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Denise Lietz		Negative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A

1	SaskPower	Wayne Guttormson		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A
1	Xcel Energy, Inc.	Greg Pieper		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	N/A
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

2	Independent Electricity System Operator	Leonard Kula	Mark Wilson	Negative	N/A
2	ISO New England, Inc.	Matthew Goldberg		None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Sarah Kist		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Abstain	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Abstain	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A

3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Bill Hughes	Mary Downey	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Abstain	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	Fayetteville Public Works Commission	Allen Wallace		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart	Richard Hoag	Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Joshua Bach		Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Greg LeGrave		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles	Mike Anctil		None	N/A

	Department of Water and Power				
3	M and A Electric Power Cooperative	Stephen Pogue		Abstain	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Abstain	N/A
3	Northeast Utilities	Mark Kenny		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Abstain	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Terry Baker		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A

3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A

4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Mary Downey	Affirmative	N/A
4	City of Winter Park	Mark Brown		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Christopher Plante		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Keith Morisette		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	N/A

5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Scott Takinen		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Abstain	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Kaleb Brimhall		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion	Randi Heise		Abstain	N/A

	Resources, Inc.				
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Golden Spread Electric Cooperative, Inc.	Chip Koloini		None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Brett Holland		Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	Integrys Energy Group, Inc. - Wisconsin Public Service Corporation	Scott Johnson		Abstain	N/A
5	JEA	John Babik		Abstain	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Liberty Electric Power LLC	Daniel Duff		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A

5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Negative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A

5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		None	N/A
5	Westar Energy	stephanie johnson		Abstain	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Randy Young		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Abstain	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Brenda Anderson		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Abstain	N/A

6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		None	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade	Stephen York		Affirmative	N/A

	LLC				
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Seattle City Light	Dennis Sismaet		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Tiffany Lake		Abstain	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
7	Siemens - Siemens PTI	Frank McElvain		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	National Association of Regulatory Utility Commissioners	Jerry Maio		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 284 of 284 entries

Exhibit G

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Team Roster

Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations Standard Drafting Team

	Participant	Entity
Chair	Greg Vassallo	Bonneville Power Administration (BPA)
Member	José Conto	Electric Reliability Council of Texas (ERCOT)
Member	Bill Harm	PJM Interconnection, LLC
Member	Sharma Kolluri	Entergy
Member	Charles-Eric Langlois	Hydro-Québec TransÉnergie
Member	Manish Patel	Southern Company
Member	Fabio Rodriguez, P.E.	Duke Energy – Florida
Member	Hari Singh	Xcel Energy
Member	Matthew H. Tackett, P.E.	Midcontinent Independent System Operator (MISO)
NERC staff	Scott Barfield-McGinnis, P.E. (Standards Developer)[1]	North American Electric Reliability Corporation (NERC)
NERC staff	Erika Chanzes (Standards Developer)[2]	North American Electric Reliability Corporation (NERC)
NERC staff	Shamai Elstein (Senior Counsel)	North American Electric Reliability Corporation (NERC)
NERC staff	Lacey Ourso(Standards Developer)[3]	North American Electric Reliability Corporation (NERC)
NERC staff	Kathrine Street (Standards Developer)[4]	North American Electric Reliability Corporation (NERC)

[1] Led 2008-02.2 Phase 2 to align PRC-010-1 with PRC-004-3.

[2] Initiated 2008-02 to revise PRC-010-0 and retire PRC-020-1, PRC-021-1, and PRC-022-1.

[3] Led 2008-02 work to revise PRC-006-1.

[4] Finished 2008-02 to revise PRC-010-0 and retire PRC-020-1, PRC-021-1, and PRC-022-1 due to E. Chanzes reassignment.

Version	Date	Description
1.0	05/21/13	Initial posting
2.0	06/07/13	Corrected F. Rodriguez's entity name
3.0	08/26/13	Removed B. Joffs from roster due to resignation from SDT
4.0	10/01/13	Removed A. Sleva from roster due to resignation from SDT
5.0	01/15/2015	Removed P. Tatro from roster due to resignation from NERC Added footnotes and W. Edwards
6.0	03/18/2015	Removed W. Edwards from roster due to resignation from NERC

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

May 8, 2015

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Errata to Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards PRC-004-2.1(i)a, PRC-004-4, PRC-005-2(i), PRC-005-3(i), and VAR-002-4
Docket No. RD15-3-000

Dear Ms. Bose:

On February 6, 2015, the North American Electric Reliability Corporation ("NERC") filed a petition for approval of proposed Reliability Standards PRC-004-2.1(i)a, PRC-004-4, PRC-005-2(i), PRC-005-3(i), and VAR-002-4 ("Petition"), with the Federal Energy Regulatory Commission ("Commission").

It has come to NERC's attention that the Implementation Plans for PRC-005-2(i) and PRC-005-3(i), as submitted to the Commission in the Petition, need to be modified to properly sequence the version numbering and effective dates for PRC-005-2(i) and PRC-005-3(i) to ensure that the implementation of these Reliability Standards carries forth the intention of the standard drafting team responsible for development. The errata clarifies that PRC-005-2(i) should become effective concurrently with or after the effective date of PRC-005-2, and that PRC-005-3(i) should become effective concurrently with or after the effective date of PRC-005-3.

The proposed modifications are identified in the redline versions of the revised Implementation Plans, submitted herein as **Exhibit A**. The proposed clean versions of the revised Implementation Plans, which shall replace the Implementation Plans for PRC-005-2(i) and PRC-005-3(i) in the Petition, are submitted as **Exhibit B**.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

For the reasons set forth above, NERC respectfully requests that the Commission approve the proposed errata to the Implementation Plans for PRC-005-2(i) and PRC-005-3(i)**,** effective as proposed herein.

Respectfully submitted,

/s/ Milena Yordanova

Milena Yordanova
Counsel for the North American Electric Reliability Corporation

cc: Official service list in Docket No. RD15-3-000.

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 8th day of May, 2015.

/s/ Milena Yordanova

Milena Yordanova
Counsel for the North American Electric Reliability Corporation

Exhibit A

Implementation Plans for PRC-005-2(i) and PRC-005-3(i) _Redline Version

PRC-005-2(i)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-2(i)

~~The standard numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.~~

Standards Involved

Approval:

- PRC-005-2(i) – Protection System Maintenance

Retirement:

- PRC-005-2 – Protection System Maintenance

Prerequisite Approvals:

N/A

Background:

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Reliability Standard PRC-005-2, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2012. The SDT has revised the applicability section of PRC-005-2 to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations:

PRC-005-2(i) is proposed for approval to align the applicability section of PRC-005-2 with the revised definition of "Bulk Electric System." PRC-005-2 may already be retired pursuant to an implementation plan of a successor version of PRC-005 ~~by the time the revised definition of "Bulk Electric System"~~before PRC-005-2(i) becomes effective. If this occurs, PRC-005-2(i) will not go into effect.

Effective Date

PRC-005-2(i) shall become effective on the later of the first day following the Effective Date of PRC-005-2 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-005-2 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-2.~~

Retirement of Existing Standards:

PRC-005-2 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-2(i) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

All aspects of the Implementation Plan for PRC-005-2 will remain applicable to PRC-005-2(i) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-2 is available here.

PRC-005-3(i)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-3(i)

~~The standard numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.~~

Standards Involved

Approval:

- PRC-005-3(i) – Protection System and Automatic Reclosing Maintenance

Retirement:

- PRC-005-2(i) – Protection System Maintenance
- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals

N/A

Background

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Reliability Standard PRC-005-3, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2013. The SDT has revised the applicability section of PRC-005-3 to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations

PRC-005-3(i) is proposed for approval to align the applicability section of PRC-005-3 with the revised definition of "Bulk Electric System." PRC-005-3 may already be retired pursuant to an Implementation Plan of a successor version of PRC-005 ~~by the time the revised definition of "Bulk Electric System"~~ before PRC-005-3(i) becomes effective. If this occurs, PRC-005-3(i) will not go into effect.

Effective Date

PRC-005-3(i) shall become effective on the later of the first day following the Effective Date of PRC-005-3 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-005-3 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~on the later of the effective date of the revised definition of Bulk Electric System or the first day following the effective date of PRC-005-3.~~

Retirement of Existing Standards

PRC-005-3 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-3(i) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

PRC-005-3(i~~X~~) only modifies the applicability for PRC-005-3. All aspects of the Implementation Plan for PRC-005-3 will remain applicable to PRC-005-3(i) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-3 is available here.

Exhibit B

Implementation Plans for PRC-005-2(i) and PRC-005-3(i) _Clean Version

PRC-005-2(i)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-2(i)

Standards Involved

Approval:

- PRC-005-2(i) – Protection System Maintenance

Retirement:

- PRC-005-2 – Protection System Maintenance

Prerequisite Approvals:

N/A

Background:

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Reliability Standard PRC-005-2, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2012. The SDT has revised the applicability section of PRC-005-2 to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations:

PRC-005-2(i) is proposed for approval to align the applicability section of PRC-005-2 with the revised definition of "Bulk Electric System." PRC-005-2 may already be retired pursuant to an implementation plan of a successor version of PRC-005 before PRC-005-2(i) becomes effective. If this occurs, PRC-005-2(i) will not go into effect.

Effective Date

PRC-005-2(i) shall become effective on the later of the first day following the Effective Date of PRC-005-2 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-005-2 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

PRC-005-2 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-2(i) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

All aspects of the Implementation Plan for PRC-005-2 will remain applicable to PRC-005-2(i) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-2 is available here.

PRC-005-3(i)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2014-01 Standards Applicability for Dispersed Power Producing Resources
PRC-005-3(i)

Standards Involved

Approval:

- PRC-005-3(i) – Protection System and Automatic Reclosing Maintenance

Retirement:

- PRC-005-2(i) – Protection System Maintenance
- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals

N/A

Background

In light of the adoption of a revised "Bulk Electric System" definition by the Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-005, are necessary to align with the implementation of the revised "Bulk Electric System" definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section of certain Generator Owner/Generator Operator requirements to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

Reliability Standard PRC-005-3, with its associated Implementation Plan, was adopted by the NERC Board of Trustees on November 7, 2013. The SDT has revised the applicability section of PRC-005-3 to align with the revised definition of "Bulk Electric System" in the event that this version of PRC-005 is mandatory and enforceable on the effective date of the revised definition of "Bulk Electric System."

General Considerations

PRC-005-3(i) is proposed for approval to align the applicability section of PRC-005-3 with the revised definition of "Bulk Electric System." PRC-005-3 may already be retired pursuant to an Implementation Plan of a successor version of PRC-005 before PRC-005-3(i) becomes effective. If this occurs, PRC-005-3(i) will not go into effect.

Effective Date

PRC-005-3(i) shall become effective on the later of the first day following the Effective Date of PRC-005-3 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-005-3 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards

PRC-005-3 shall be retired at midnight of the day immediately prior to the effective date of PRC-005-3(i) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

PRC-005-3(i) only modifies the applicability for PRC-005-3. All aspects of the Implementation Plan for PRC-005-3 will remain applicable to PRC-005-3(i) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-005-3 is available here.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)**	**Docket No. RM15-16-___**
	)	

SUPPLEMENTAL INFORMATION TO PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED TRANSMISSION OPERATIONS AND INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION RELIABILITY STANDARDS

Pursuant to Section 215(d)(1) of the Federal Power Act[1] and Section 39.5[2] of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the North American Electric Reliability Corporation ("NERC")[3] hereby submits supplemental information to its March 18, 2015 petition for approval of nine proposed Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards (the "TOP/IRO Petition").[4] NERC is providing this supplemental information to address the removal of Load Serving Entities ("LSEs") from the applicability of proposed Reliability Standard TOP-001-3 in light of the Commission's order on NERC's Risk-Based Registration ("RBR") initiative.[5]

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2014).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the Federal Power Act ("FPA") on July 20, 2006. *North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006).

4 The nine proposed Reliability Standards are: TOP-001-3 (Transmission Operations); TOP-002-4 (Operations Planning); TOP-003-3 (Operational Reliability Data); IRO-001-4 (Reliability Coordination – Responsibilities); IRO-002-4 (Reliability Coordination –Monitoring and Analysis); IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments); IRO-010-2 (Reliability Coordinator Data Specification and Collection); IRO-014-3 (Coordination Among Reliability Coordinators); and IRO-017-1 (Outage Coordination) (collectively, the "Proposed TOP/IRO Standards").

5 *North American Electric Reliability Corporation*, 150 FERC ¶ 61,213 (2015) ("RBR Order").

I. BACKGROUND

a. Applicability of Proposed Reliability Standard TOP-001-3

As discussed in greater detail in the TOP/IRO Petition, proposed Reliability Standard TOP-001-3 contains 20 requirements relating to transmission operations and applies primarily to the responsibilities of Transmission Operators and Balancing Authorities for maintaining reliable operations.[6] The only other functional entities subject to requirements under proposed Reliability Standard TOP-001-3 are Distribution Providers and Generator Operators, whose sole responsibilities under the proposed standard are to:

- comply with Operating Instructions[7] issued by a Transmission Operator or Balancing Authority (Requirements R3 and R5); or
- notify the Transmission Operator or Balancing Authority if they are unable to comply with the Transmission Operator's or Balancing Authority's Operating Instructions (Requirements R4 and R6).

As explained in the TOP/IRO Petition, proposed Reliability Standard TOP-001-3 replaces currently-effective Reliability Standards TOP-001-1a and certain requirements from other currently-effective TOP and IRO Reliability Standards.[8] The requirement for Distribution Providers and Generator Operators to comply with Operating Instructions issued by a Transmission Operator is a carry-over from Reliability Standard TOP-001-1a, Requirements R3 and R4, which require Generator Operators (Requirement R3) and Distribution Providers (Requirement R4) to comply with "reliability directives" issued by a Transmission Operator unless

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6 *See* TOP/IRO Petition at 21-26.

7 As defined in the Glossary of Terms Used in NERC Reliability Standards, an "Operating Instruction" is "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)."

8 *See* Exhibit D to the TOP/IRO Petition.

such actions would violate safety, equipment, regulatory or statutory requirements.[9] Requirement R4 also required LSEs to comply with the reliability directives issued by a Transmission Operator. LSEs were not subject to any other requirements in TOP-001-1a nor were LSEs subject to the other currently-effective TOP/IRO requirements that proposed Reliability Standard TOP-001-3 is designed to replace. While LSEs were initially included in Requirements R3-R6 of proposed Reliability Standard TOP-001-3 along with Distribution Providers and Generator Operators, the standard drafting team decided to remove LSEs from the proposed standard following the NERC Board of Trustee's approval of proposed revisions to the NERC Rules of Procedure to eliminate the LSE functional registration category.

The proposal to eliminate the LSE functional registration category was part of a broader initiative at NERC, referred to as the RBR initiative, to revise the NERC registration criteria to ensure that the right entities are subject to the right set of Reliability Standards using a consistent approach to risk assessment and registration. The goal of the RBR initiative was to develop enhanced registry criteria, including the use of thresholds and specific Reliability Standards applicability, where appropriate, to better align compliance obligations with material risk to Bulk Electric System reliability. Eliminating the LSE functional registration category was one of a number of reforms proposed as part of the RBR initiative. On December 11, 2014, in Docket No. RR15-4-000, NERC filed a petition with the Commission for approval of proposed revisions to the NERC Rules of Procure to implement the reforms proposed as part of the RBR initiative (the "RBR Petition").

[9] As explained in the TOP/IRO Petition (at 20-21), the term "Operating Instruction" replaces the term "reliability directive" used in currently effective Reliability Standards TOP-001-1a. TOP-001-1a did not require Generator Operators, Distribution Providers, or LSEs to comply with reliability directives issued by a Balancing Authority.

b. RBR Order

On March 19, 2015, the Commission issued the RBR Order, ruling on the RBR Petition. Among other things, the Commission denied, without prejudice, NERC's proposal to remove the LSE function and directed NERC to submit a compliance filing providing additional information on the effect of deregistering LSEs.[10] The Commission found NERC's analysis incomplete, stating that it is concerned that NERC has not adequately explained how certain LSE reliability tasks will be performed going forward.[11] In particular, the Commission focused on the LSEs' role as a provider of information required for reliable operation of the Bulk Electric System.[12] The Commission stated:

> Upon elimination of the load-serving entity as a registered function, it is unclear whether and how some entities will continue to provide information or who will assume their obligations. It appears that some of the load-serving entities will be required to continue to provide the information through their responsibilities as other registered functions. However, NERC has not adequately explained which entities will continue to provide this information. Because of the gaps in NERC's analysis, discussed below, we are unable to satisfactorily conclude on the current record in this proceeding that the elimination of the load-serving entity function will have no material impact on the reliability of the Bulk-Power System.[13]

More specifically, the Commission expressed concern with the information provided by LSEs that serve as inputs into power system models and assessments under the Modeling, Data, and Analysis ("MOD") group of Reliability Standards:

> NERC does not adequately address whether, going forward, all balancing authorities and planners will have the ability to reasonably estimate demand and energy forecast data for areas where the load-serving entity is deregistered. In areas

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[10] RBR Order at PP 37-43.

[11] *Id*.

[12] RBR Order at PP 37-41. As provided in the NERC Functional Model (at 55), LSEs, among other things, provide (1) load profiles and characteristics, plans, and forecasts as needed to the Balancing Authorities, Purchasing-Selling Entities, Planning Coordinators, Resource Planners, and Transmission Planners, (2) information as to self-provided reliability-related services to the Balancing Authority, and (3) generation commitments and dispatch schedules to the Balancing Authority.

[13] RBR Order at P 37.

> of significant load-growth, the cumulative effect of deregistered entities not having to provide accurate load data projections as required by certain MOD Reliability Standards could have an increasing effect on reliability over time as load increases, e.g., as a result of demand and energy forecast data omitted or not accurately depicted in power system models and assessments.[14]

To obtain additional information about the effects of deregistering LSEs, the Commission directed NERC to submit a compliance filing that provides, among other things: (1) an adjusted estimate on the number of LSEs that would be deregistered; (2) additional information regarding the peak load of such entities on an individual and balancing authority basis; and (3) for the LSEs for which NERC anticipates deregistration, specific information regarding the alternative sources of authority which will ensure the continuation of LSE reliability activities by either the deregistered entity or another registered entity.[15]

Additionally, in response to NERC's statement that NERC is in the process of removing the LSE function from a number of Reliability Standards, the Commission stated:

> When and if NERC submits one or more petitions for revised Reliability Standards that propose to remove the load-serving entity as an applicable entity, NERC must provide an adequate explanation of how the previous load-serving entities obligations will continue. In particular, an explanation that the removal of the load-serving entity function is consistent with the RBR initiative would be inadequate, if not circular, in light of NERC's rationale in the immediate docket that the impact from eliminating the load-serving entity function is lessened by the removal of the function from Reliability Standards. NERC is responsible to explain in the context of a particular modified Reliability Standard whether removal of the load-serving entity would result in a reliability gap and, if so, how the gap is addressed.[16]

In light of this directive, NERC is providing supplemental information to the TOP/IRO Petition to provide further explanation for removing LSEs as an applicable entity under proposed Reliability Standard TOP-001-3. As explained below, removing LSEs from proposed Reliability

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[14] RBR Order at P 40 (internal citations omitted).

[15] RBR Order at P 41.

[16] RBR Order at P 43 (internal citations omitted).

Standard TOP-001-3 will not create a reliability gap, and the Commission should approve proposed Reliability Standard TOP-001-3 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. SUPPLEMENTAL INFORMATION

The stated purpose of proposed Reliability Standard TOP-001-3 is to "prevent instability, uncontrolled separation, or Cascading outages that adversely affect the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences."[17] As noted above, the proposed standard achieves this reliability goal, in part, by providing Transmission Operators and Balancing Authorities the authority to direct the actions of certain other functional entities (via the issuance of Operating Instructions) to maintain reliability during Real-time operations. In contrast to prior versions of proposed Reliability Standard TOP-001-3, LSEs are not included in the list of entities that must comply with a Transmission Operator's or Balancing Authority's Operating Instructions.[18] As explained below, that is because none of the functions performed by LSEs, as described in the NERC Functional Model, necessitate that LSEs be subject to a requirement to comply with such Operating Instructions to ensure that a Transmission Operator or Balancing Authority can maintain the reliability of its Transmission Operator Area or Balancing Authority Area, respectively.

As explained in the NERC Functional Model,[19] an LSE is "the functional entity that secures energy and transmission service (and reliability-related services) to serve the electrical demand

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[17] *See* TOP/IRO Petition at 21.

[18] As noted above, the only requirement in previous versions of proposed Reliability Standard TOP-001-3 applicable to LSEs was for LSEs to comply with "reliability directives" issued by a Transmission Operator. There was previously no requirement for LSEs to comply with the directives of a Balancing Authority.

[19] The NERC Functional Model is available at: http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf The NERC Functional Model was approved by the NERC Board of Trustees and provides the framework for the development and applicability of NERC's Reliability Standards. See *Mandatory Reliability Standards for the Bulk-*

and energy requirements of its end-use customers."[20] An LSE does not own or operate Bulk Electric System facilities or equipment or the facilities or equipment used to serve end-use customers.[21] As provided in the NERC Functional Model, an LSE's tasks are limited to the following:

1. *Ahead of Time Ta*sks:
    - Submits load profiles and characteristics, plans, and forecasts to Balancing Authorities, Purchasing-Selling Entities, Planning Coordinators, Resource Planners, and Transmission Planners.
    - Identifies new facility connection needs for end-use customers.
    - Provides generation commitments and dispatch schedules to the Balancing Authority.
    - Provides information as to self-provided reliability-related services to the Balancing Authority.
    - Provides planned purchases to the Resource Planner and Transmission Planner for system modeling and reliability evaluation.
    - Arranges for transmission service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
    - Submits Requests For Interchange to Interchange Coordinators.
    - Notifies Generator Operators if Arranged Interchange requests are approved or denied.
    - Receives final approval or denial of Arranged Interchange from Interchange Coordinator.
    - Coordinates with Distribution Provider on identifying new facility interconnection needs.
    - Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.

Power System, Order No. 693, 72 FR 16416 at PP 117-129 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[20] NERC Functional Model at 55. As defined in the NERC Glossary, an LSE "[s]ecures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers."

[21] The Distribution Provider is the functional entity that provides facilities that interconnect an end-use customer load and the electric system for the transfer of electrical energy to the end-use customer. If a company registered as an LSE also owned facilities, the company would be registered for other functions as well.

2. *Real-Time Tasks*:

- Receives requests from the Balancing Authority and Distribution Provider for voluntary load curtailment.
- Communicates requests for voluntary load curtailment to end-use customers as directed by the Balancing Authority and Distribution Provider.
- Notifies Interchange Coordinators of Confirmed Interchange cancellations or terminations.
- Receives notice of Confirmed Interchange curtailments from Interchange Coordinator.[22]

In evaluating these functional obligations, the standard drafting team for proposed Reliability Standard TOP-001-3 did not identify any circumstances under which a Transmission Operator or Balancing Authority would need to issue an Operating Instruction to an LSE to meet the goal of the standard (i.e., to prevent instability, uncontrolled separation, or Cascading outages that adversely affect the reliability of the Interconnection in Real-time).[23] First, with respect to the LSE's role as a provider of information to other functional entities, which was the Commission's focus in the RBR Order, that role is primarily carried out ahead of Real-time and would not be the subject of an Operating Instruction. For instance, the LSE's submission of (1) load profiles and characteristics, plans, and forecasts, (2) generation commitments and dispatch schedules, and (3) information as to self-provided reliability related services to the Balancing Authority occurs in advance of Real-time operations. As explained above, the purpose of issuing Operating Instructions is to provide Transmission Operators and Balancing Authorities the authority to direct the actions of others so as to maintain reliable transmission operation in Real-time. Proposed

[22] NERC Functional Model at 55.

[23] In its compliance filing on the RBR Order, NERC will provide further analysis on removing the LSE function from currently-effective Reliability Standards and proposed Reliability Standards pending Commission approval. This supplement solely focusses on the removal of the LSE from proposed Reliability Standard TOP-001-3.

Reliability Standard TOP-001-3 is not the standard by which Transmission Operators or Balancing Authorities obtain operational or planning data from other functional entities.

Additionally, the LSE's Real-time role with respect to voluntary load curtailment does not necessitate requiring LSEs to comply with Operating Instructions issued by a Transmission Operator or Balancing Authority. In order to maintain reliability in their areas and prevent instability, uncontrolled separation, or Cascading outages, there may be circumstances under which Transmission Operators and Balancing Authorities need to shed load (i.e. direct non-voluntary load curtailment). Such action is implemented in Real time to address imminent or existing reliability issues such as an exceedance of an Interconnection Reliability Operating Limit or System Operating Limit, or a voltage problem. Due to the urgent nature of these circumstances, the Reliability Coordinator, Balancing Authority, or Transmission Operator may issue Operating Instructions directly to the Distribution Provider for physical implementation of load shedding (except when this can be accomplished directly by the Transmission Operator). As indicated by the NERC Functional Model, as the LSE does not own or operate equipment, the LSE does not play a role in shedding load in Real-time.[24] It is the Distribution Provider that provides the switches and reclosers used to shed load for emergency action at the direction of the Transmission Operator or Balancing Authority.[25]

In contrast to a Distribution Provider's role in load shedding, the LSE's role in load curtailment is voluntary and typically arranged ahead of Real-time. In many cases, the LSE obtains interruptible load contracts with end-use customers for the purpose of providing market price relief

[24] Because the LSE does not own or operate equipment, LSEs cannot shed load or perform other corrective actions. LSEs thus have no control that they could exercise for purposes of load shedding even if they were directed to take action by a Transmission Operator or Balancing Authority.

[25] NERC Functional Model at 47.

or assistance to the Balancing Authority in tight capacity/energy situations. The LSE often notifies the Balancing Authorities and Distribution Providers of the agreements so that voluntary load curtailment may be requested under specified conditions.[26] In Real-time, the LSE's role is simply to "[c]ommunicate requests for *voluntary* load curtailment to end-use customers as directed by the Balancing Authority and Distribution Provider."[27] An LSE's compliance with such requests, however, is not necessary for the Transmission Operator or Balancing Authority to maintain reliability in its area. Transmission Operators and Balancing Authorities have the ability to shed load absent agreement by the LSE or the end-use customer, as noted above. Requiring an LSE to comply with an Operating Instruction to exercise its rights to curtail load is thus unnecessary to maintain reliability and prevent instability, uncontrolled separation, or Cascading outages. If an LSE receives a request from a Transmission Operator or Balancing Authority to curtail load, the LSE may exercise its contractual rights to curtail or risk having its load shed by the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider according to established load shedding procedures.[28]

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[26] Voluntary load curtailment is a tool used to address capacity deficiencies, not to control transmission constraints. Under Reliability Standard EOP-001-2.1b, Requirement R4, each Transmission Operator and Balancing Authority must have an emergency plan that includes, among other things, public appeals for voluntary load reductions and energy conservation. Similarly, under proposed Reliability Standard EOP-011-1, Requirement R2, Balancing Authorities must have an Operating Plan to mitigate Capacity Emergencies and Energy Emergencies that includes, among other things, public appeals for voluntary load reductions. Removing LSEs from proposed Reliability Standard TOP-001-3 does not change the requirement for Transmission Operators and Balancing Authorities to appeal for voluntary load reduction from an LSE or directly from end-use customers. Note that LSEs are not an applicable entity under EOP-001-2.1b or EOP-011-1.

[27] NERC Functional Model at 55 (emphasis added).

[28] NERC's Reliability Standards should not dictate when an LSE must exercise its contractual rights to curtail load, particularly where there are other mechanisms to maintain reliable operations.

III. Conclusion

NERC respectfully requests that the Commission consider the supplemental information provided herein and approve the proposed TOP and IRO Reliability Standards as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Respectfully submitted,

/s/ Shamai Elstein

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Date: May 12, 2015

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151 FERC ¶ 61,186
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

May 29, 2015

In Reply Refer To:
North American Electric
Reliability Corporation
Docket No. RD15-3-000

Holly A. Hawkins
Associate General Counsel
1325 G Street, NW
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Washington, DC 20005

Reference: Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards PRC-004-2.1(i)a, PRC-004-4, PRC-005-2(i), PRC-005-3(i), and VAR-002-4.

Dear Ms. Hawkins:

1. On February 6, 2015, the North American Electric Reliability Corporation (NERC) submitted a petition seeking approval of Reliability Standards PRC-004-2.1(i)a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations), PRC-004-4 (Protection System Misoperation Identification and Correction), PRC-005-2(i) (Protection System Maintenance), PRC-005-3(i) (Protection System and Automatic Reclosing Maintenance), and VAR-002-4 (Generator Operation for Maintaining Network Voltage Schedules), pursuant to section 215(d) of the Federal Power Act (FPA).[1] On March 13, 2015, NERC submitted a supplemental petition seeking approval of three additional Reliability Standards: PRC-001-1.1(ii) (System Protection Coordination), PRC-019-2 (Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection), and PRC-024-2 (Generator Frequency and Voltage Protective Relay Settings). NERC states that it has modified the Reliability Standards to adjust the applicability to owners of dispersed generation

[1] 16 U.S.C. § 824o(d) (2012).

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resources.[2] On May 8, 2015, NERC submitted errata to the February 6 petition, modifying the implementation plans for PRC-005-2(i) and PRC-005-3(i) to properly sequence the version numbering and effective dates for PRC-005-2(i) and PRC-005-3(i) to ensure that the implementation of these Reliability Standards carries forth the intention of the standard drafting team responsible for development. The errata clarifies that PRC-005-2(i) should become effective concurrently with or after the effective date of PRC-005-2, and that PRC-005-3(i) should become effective concurrently with or after the effective date of PRC-005-3.

2. The Commission-approved definition of "bulk electric system," inclusion I4, provides:

> Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above.

Thus, under inclusion I4, the elements designated as bulk electric system are: (i) the individual resources; and (ii) the system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

3. In its Petition, NERC states it revised certain provisions of the identified Reliability Standards to ensure that only those dispersed generation resources that could affect the reliability of the Bulk-Power System are subject to the standards. NERC provides a detailed description of the standard drafting team considerations for each reviewed Reliability Standard, which is further discussed in a "draft white paper."[3]

4. NERC explains that the design and operational characteristics of dispersed power producing resources are different than traditional generation. In particular, dispersed power producing resources are typically comprised of many individual generating units and, in most instances the units are similar in design and produced by the same

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[2] *See* February 6 Petition at 1, fn.4. "Dispersed generation resources as used in this Petition refer to variable generation that depends on a primary fuel source which varies over time and cannot be stored." *See also* March 13 Supp. Petition at 2, fn.4.

[3] *Id.* at 10. *See also* February 6 Petition, Ex. C (Draft Technical White Paper) *Proposed Revisions to the Applicability of NERC Reliability Standards to Dispersed Generation Resources*.

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manufacturer. The aggregated capability of the facility may contribute significantly to the reliability of the Bulk-Power System, and therefore, the equipment utilized to aggregate the individual units to a common point of interconnection with the transmission system should be operated and maintained as required by the NERC Reliability Standards subject to these petitions. Thus, NERC proposes to modify each of the identified Reliability Standards to include applicability language in provisions pertaining to generator owners and generator operators of resources identified through inclusion I4 of the bulk electric system definition.

5. The specific Reliability Standard provisions revised by NERC to affect this limitation of applicability consistent with the bulk electric system definition pursuant to inclusion I4 are as follows:

PRC-001-1.1(ii), Requirement R3;

PRC-004-2.1(i)a Requirements R2 and R3, and PRC-004-4, all requirements;[4]

PRC-005-2(i) and PRC-005-3(i), all requirements;

PRC-019-2, all requirements;

PRC-024-2, Requirements R1 and R2; and

VAR-002-4, Requirements R4 and R5.

[4] NERC explains that it submitted multiple versions of Reliability Standards PRC-004 and PRC-005 in order to include dispersed generation provisions in both: (1) the currently effective version of each standard; and (2) the previously modified version of each standard that was pending before the Commission at the time NERC submitted its petition in the immediate docket. Since the submission of NERC's petition in this docket, the Commission approved the pending Reliability Standards, PRC-004-3 and PRC-005-3. *See Protection System Maintenance Reliability Standard*, Order No. 803, 150 FERC ¶ 61,039 (2015) (approving PRC-005-3); *North American Electric Reliability Corp.*, 151 FERC ¶ 61,129 (2015) (approving PRC-004-3). In the immediate proceeding, we approve the requested modifications to both the currently effective standard, and the approved but not yet effective version of the standard, to ensure continuity in the application of the provisions pertaining to dispersed generation.

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6. NERC states Reliability Standard PRC-001-1.1 is designed to ensure that system protection is coordinated among operating entities.[5] Proposed PRC-001-1.1(ii) reflects changes made to the currently-effective PRC-001-1.1.

7. NERC states currently-effective Reliability Standard PRC-004-2.1a is designed to ensure that all transmission and generation protection system misoperations affecting the reliability of the bulk electric system are analyzed and mitigated.[6] NERC states the proposed PRC-004-2.1(i)a reflects changes made to the currently-effective Reliability Standard PRC-004-2.1a. Proposed PRC-004-4 reflects changes made to Reliability Standard version PRC-004-3.[7]

8. NERC states that the purpose of PRC-005-3 is to document and implement programs for the maintenance of all protection systems and automatic reclosing affecting the reliability of the bulk electric system so that they are kept in working order and the proposed PRC-005-3(i) reflects changes to PRC-005-3. NERC explains the revisions included in PRC-005-2(i) and PRC-005-3(i) are necessary to ensure the proposed changes will continue to be carried forward while the versions of this Reliability Standard are being enhanced to ensure the reliability of the Bulk-Power System.[8] NERC Reliability Standard PRC-005-2 became enforceable on April 1, 2015.[9] NERC states the proposed PRC-005-2(i) reflects changes to PRC-005-2. Reliability Standard PRC-005-3 becomes effective April 1, 2016.[10]

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[5] *See North American Electric Reliability Corp.*, 138 FERC ¶ 61,095 (2012) (approving PRC-001-1.1).

[6] *See Generator Requirements at the Transmission Interface*, Order No. 785, 144 FERC ¶ 61,221 (2012) (approving PRC-004-2.1a and clarifying that the requirements in PRC-004 extend not only to protection systems associated with the generating facility or station, but also to protection systems associated with the generator interconnection facilities).

[7] *North American Electric Reliability Corp.*, 151 FERC ¶ 61,129 (2015) (approving PRC-004-3).

[8] February 6 Petition at 18-19.

[9] *Protection System Maintenance Reliability Standard*, Order No. 793, 145 FERC ¶ 61,253 (2013) (approving PRC-005-2).

[10] *Protection System Maintenance Reliability Standard*, Order No. 803, 150 FERC ¶ 61,039 (2015) (approving PRC-005-3).

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9. NERC states that currently-effective Reliability Standard PRC-019-1 is designed to verify coordination of generating unit facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and protection system settings.[11]

10. NERC states currently-effective Reliability Standard PRC-024-1 is designed to ensure generator owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.[12]

11. NERC states currently-effective Reliability Standard VAR-002-3 ensures that generators provide reactive support and voltage control within the generating facility capabilities in order to protect equipment and maintain reliable operation of the Interconnection.[13]

12. NERC proposes an implementation plan for each of the revised currently-effective Reliability Standards with each plan having an effective date "immediately after the standard is approved" by the Commission (or similar language). For revisions to Commission-approved Reliability Standards pending implementation, NERC proposes the effective dates of these revised standards should not alter the timing of concurrent standards development of PRC projects.

13. Notice of NERC's initial petition was issued on February 6, 2015 and published on February 12, with comments, protests and motions to intervene due on or before March 9, 2015. Notice of NERC's supplemental petition was issued on March 25, 2015 with comments, protests, and motions to intervene due on or before April 9, 2015. Dominion Resources Services, Inc. filed a timely motion to intervene and comments in support of NERC's Petition.

14. Pursuant to section 215(d)(2) of the FPA, we approve Reliability Standards PRC-001-1.1(ii), PRC-004-2.1(i)a, PRC-004-4, PRC-005-2(i), PRC-005-3(i), PRC-019-2, PRC-024-2, and VAR-002-4 and find that the standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. We also approve the

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[11] *Generator Verification Reliability Standards*, Order No. 796, 146 FERC ¶ 61,213 (2014) (approving PRC-019-1 and PRC-024-1).

[12] Order No. 796, 146 FERC ¶ 61,213 (2014) (approving PRC-019-1 and PRC-024-1).

[13] *North American Electric Reliability Corporation*, Docket No. RD14-11-000 (Aug. 1, 2014) (delegated letter order approving VAR-002-3).

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associated implementation plans and effective dates submitted by NERC for each Reliability Standard.

15. The information collection requirements contained in this order are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[14] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[15]

16. The revisions to eight Reliability Standards, approved in this order, are designed to clarify the applicability to owners of dispersed power producing resources. These entities comprise a subset of the generator owners in the NERC Compliance Registry. The eight Reliability Standards in this proceeding were previously approved by the Commission. The clarifications align existing responsibilities with current operating practices, and the Commission does not expect it to affect entities' current reporting burden.[16] Accordingly, we will submit this order to OMB for informational purposes only.

By direction of the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[14] 44 U.S.C. § 3507(d) (2012).

[15] 5 C.F.R. 1320.11 (2014).

[16] The reporting requirements for Reliability Standard PRC-004-3, approved by the Commission in Docket No. RD14-14, will be submitted to OMB for review under FERC-725G1. Details on the respondents, filing requirements, and associated burden for the other standards were included in the burden estimates reviewed and approved earlier by OMB.

Document Content(s)

RD15-3-000.DOCX.....1-6

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

North American Electric Reliability Corporation
Docket No. RR15-7-000

May 5, 2015

North American Electric Reliability Corporation
1325 G Street NW, Suite 600
Washington, DC 20005

Attention: Andrew C. Wills
Associate Counsel

Reference: Amendments to Delegation Agreement with Texas Reliability Entity, Inc.

Dear Mr. Wills:

On February 27, 2015, North American Electric Reliability Corporation (NERC) submitted amendments to the Delegation Agreement between NERC and Texas Reliability Entity, Inc. (TRE), specifically to revise the TRE Bylaws.

Notice of this filing was issued on March 2, 2015, with protests and interventions due on or before March 20, 2015. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No protests were filed.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307 as of the date as this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may

hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power Regulation-Central

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

North American Electric Reliability Corporation
Docket No. RR14-6-002

June 4, 2015

Schiff Hardin LLP
233 South Wacker Drive, Suite 6600
Chicago, IL 60606

Attention: Owen E. MacBride
Attorney for North American Electric Reliability Corporation

Reference: Expenditure Greater than $500,000 from Operating Reserves

Dear Mr. MacBride:

On May 14, 2015, North American Electric Reliability Corporation (NERC) submitted a request for approval to spend up to $600,000 from its operating reserves during 2015 to expedite development and implementation of a centralized corporate document management program, which NERC states will support various important business requirements that are central to its operations.[1]

Notice of this filing was issued on May 14, 2015, with protests and interventions due on or before May 21, 2015. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure 18 C.F.R. § 385.214. No protests were filed.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or

[1] NERC's request is made pursuant to Paragraph 7(b)(ii) of the Settlement Agreement that was approved in *North American Electric Reliability Corp.*, 142 FERC ¶ 61,042 (2013).

procedures pursuant to 18 C.F.R. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power Regulation-Central

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151 FERC ¶ 61,134
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-11-000]

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

(May 14, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events). Proposed Reliability Standard TPL-007-1 establishes requirements for certain entities to assess the vulnerability of their transmission systems to geomagnetic disturbance events (GMDs), which occur when the sun ejects charged particles that interact and cause changes in the earth's magnetic fields. Entities that do not meet certain performance requirements, based on the results of their vulnerability assessments, must develop a plan to achieve the requirements. The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, submitted the proposed Reliability Standard for Commission approval in response to a Commission directive in Order No. 779. In addition, the Commission proposes to direct that NERC develop modifications to the benchmark GMD event definition set forth in Attachment 1 of the proposed Reliability Standard so that the

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definition is not based solely on spatially-averaged data. The Commission also proposes to direct NERC to submit a work plan, and subsequently one or more informational filings, that address specific GMD-related research areas.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document

FOR FURTHER INFORMATION CONTACT:

Regis Binder (Technical Information)
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Matthew Vlissides (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission

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888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8408
Matthew.Vlissides@ferc.gov

SUPPLEMENTARY INFORMATION:

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151 FERC ¶ 61,134
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events — Docket No. RM15-11-000

NOTICE OF PROPOSED RULEMAKING

(May 14, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events). Proposed Reliability Standard TPL-007-1 establishes requirements for certain entities to assess the vulnerability of their transmission systems to geomagnetic disturbance events (GMDs), which occur when the sun ejects charged particles that interact and cause changes in the earth's magnetic fields. Entities that do not meet certain performance requirements, based on the results of their vulnerability assessments, must develop a plan to achieve the requirements. The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted the proposed Reliability Standard for Commission approval in response to a Commission directive in Order No. 779.[2] The

[1] 16 U.S.C. 824o.

[2] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 78 FR 30,747 (May 23, 2013), 143 FERC ¶ 61,147, *reh'g denied*, 144 FERC ¶ 61,113 (2013).

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Commission also proposes to approve one definition for inclusion in the NERC Glossary of Terms submitted by NERC as well as the proposed Reliability Standard's associated violation risk factors and violation severity levels, implementation plan, and effective dates.[3]

2. In addition, as discussed below, the Commission proposes to direct NERC to develop modifications to Reliability Standard TPL-007-1 and submit informational filings to address certain issues described herein.

3. Geomagnetic disturbances are considered to be "high impact, low frequency" events.[4] In other words, while the probability of occurrence of a severe geomagnetic disturbance may be low, a geomagnetic disturbance of sufficient magnitude could have potentially severe consequences to the reliable operation of the Bulk-Power System.[5] Such events could cause widespread blackouts and cause damage to equipment that could result in sustained system outages.[6] On that basis, it is important that NERC, planning

[3] NERC, Glossary of Terms Used in NERC Reliability Standards (April 2015) (NERC Glossary), *available at* http://www.nerc.com/files/glossary_of_terms.pdf.

[4] *See* NERC Petition at 3; *see also* NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

[5] Order No. 779, 143 FERC ¶ 61,147 at P 15 (quoting NERC comment that "as a high-impact, low frequency event, GMDs pose a unique threat to Bulk-Power System reliability, and NERC is committed to working with stakeholders and the Commission to address these challenges consistent with its responsibilities as the ERO").

[6] *Id.* PP 3, 16 (citing NERC, 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at 69 (February 2012) (GMD Interim Report); Oak Ridge National Laboratory, Electromagnetic Pulse: Effects

(continued ...)

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coordinators, transmission planners, transmission owners and generator owners take appropriate actions to prepare to withstand potentially harmful geomagnetic disturbances. For that reason, Order No. 779 required NERC to identify what severity GMD events (i.e., benchmark GMD events) responsible entities will have to assess, and that NERC should technically support its choice. In the proposed reliability standard, NERC set the benchmark GMD event as a "1-in-100 year" event.

4. We believe, based on information available at this time, that the provisions of proposed Reliability Standard TPL-007-1 are just and reasonable and address the specific parameters for the Second Stage GMD Reliability Standards on geomagnetic disturbance events, as set forth in Order No. 779. For example, the proposed Reliability Standard requires responsible entities to maintain system models needed to complete "GMD Vulnerability Assessments" (Requirements R1 and R2),[7] have criteria for acceptable system steady state voltage performance during a benchmark GMD event (Requirement R3), and complete a GMD Vulnerability Assessment once every 60 calendar months, based on the benchmark GMD event definition described in Attachment 1 of the proposed Reliability Standard (Requirement R4). Further, if an applicable entity

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on the U.S. Power Grid: Meta-R-319 at page 1-14, Tables 4-1, 4-2, 4-3 (discussing at-risk transformers) (January 2010)).

[7] NERC proposes to define the term GMD Vulnerability Assessment to mean a "documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances." *See* NERC Petition, Ex. B (Implementation Plan for TPL-007-1) at 1.

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concludes, based on the GMD Vulnerability Assessment, that its system does not meet specified performance requirements, it must develop a corrective action plan that addresses how the performance requirements will be met (Requirement R7). We propose to determine that the framework of the proposed Reliability Standard, as outlined above, is just and reasonable and provides a basis for approval. We believe that, when tested against an appropriate benchmark GMD event, compliance with the proposed Reliability Standard should provide adequate protection for an applicable entity's system to withstand a geomagnetic disturbance based on a 1-in-100 year GMD event design.

5. Our primary concerns with the proposed Reliability Standard pertain to the benchmark GMD event described in Attachment 1 of the proposed Reliability Standard. While there is limited historical geomagnetic data and the scientific understanding of geomagnetic disturbance events is still evolving, we have concerns regarding the proposed Reliability Standard's heavy reliance on spatial averaging. Thus, while proposing to approve proposed Reliability Standard TPL-007-1, we also propose to direct NERC to make several modifications to better ensure that, going forward, the study and benchmarking of geomagnetic disturbance events are based on a more complete set of data and a reasonable scientific and engineering approach. Further, we propose specific revisions to Requirement R7 of the proposed Reliability Standard to ensure that, when an applicable entity identifies the need for a corrective action plan, the entity acts in a timely manner.

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I. Background

A. Section 215 and Mandatory Reliability Standards

6. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced in the United States by the ERO, subject to Commission oversight, or by the Commission independently.[8]

B. GMD Primer

7. GMD events occur when the sun ejects charged particles that interact and cause changes in the earth's magnetic fields.[9] Once a solar particle is ejected, it can take between 17 to 96 hours (depending on its energy level) to reach earth.[10] A geoelectric field is the electric potential (measured in volts per kilometer (V/km)) on the earth's surface and is directly related to the rate of change of the magnetic fields.[11] The geoelectric field has an amplitude and direction and acts as a voltage source that can cause geomagnetically-induced currents (GICs) to flow on long conductors, such as

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[8] 16 U.S.C. 824o(e).

[9] GMD Interim Report at i-ii. On April 30, 2015, the Space Weather Operations, Research, and Mitigation Task Force, under the auspices of the National Science and Technology Council, sought comment on a draft 2015 National Space Weather Strategy, which is designed to "articulate high-level strategic goals for enhancing National preparedness to space weather events." *National Science and Technology Council; National Space Weather Strategy*, 80 FR 24,296 (Apr. 30, 2015).

[10] GMD Interim Report at ii.

[11] *Id.*

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transmission lines.[12] The magnitude of the geoelectric field amplitude is impacted by local factors such as geomagnetic latitude and local earth conductivity.[13] Geomagnetic latitude is the proximity to earth's magnetic north and south poles, as opposed to earth's geographic poles. Local earth conductivity is the ability of the earth's crust to conduct electricity at a certain location to depths of hundreds of kilometers down to the earth's mantle. Local earth conductivity impacts the magnitude (i.e., severity) of the geoelectric fields that are formed during a GMD event by, all else being equal, a lower earth conductivity resulting in higher geoelectric fields.[14]

C. Order No. 779

8. In Order No. 779, the Commission directed NERC, pursuant to FPA section 215(d)(5), to develop and submit for approval proposed Reliability Standards that address the impact of geomagnetic disturbances on the reliable operation of the Bulk-Power System. The Commission based its directive on the potentially severe, wide-spread impact on the reliable operation of the Bulk-Power System that can be caused by GMD events and the absence of existing Reliability Standards to address GMD events.[15]

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[12] *Id.*

[13] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 4.

[14] *Id.*

[15] Order No. 779, 143 FERC ¶ 61,147 at P 3.

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9. Order No. 779 directed NERC to implement the directive in two stages. In the first stage, the Commission directed NERC to submit, within six months of the effective date of Order No. 779, one or more Reliability Standards (First Stage GMD Reliability Standards) that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System.[16]

10. In the second stage, the Commission directed NERC to submit, within 18 months of the effective date of Order No. 779, one or more Reliability Standards (Second Stage GMD Reliability Standards) that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole. The Commission directed that the Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System.[17] Order No. 779 explained that, if the assessments identify potential impacts from benchmark GMD events, the Reliability Standards should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System

[16] *Id.* P 2.

[17] *Id.*

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equipment, or otherwise, as a result of a benchmark GMD event. The Commission directed that the development of this plan could not be limited to considering operational procedures or enhanced training alone, but should, subject to the potential impacts of the benchmark GMD events identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment.[18] Order No. 779 observed that these strategies could, for example, include automatically blocking GICs from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, isolating certain equipment that is not cost effective to retrofit, or a combination thereof.

D. Order No. 797

11. In Order No. 797, the Commission approved Reliability Standard EOP-010-1 (Geomagnetic Disturbance Operations).[19] NERC submitted Reliability Standard EOP-010-1 for Commission approval in compliance with the Commission's directive in Order No. 779 corresponding to the First Stage GMD Reliability Standards. In Order No. 797-A, the Commission denied the Foundation for Resilient Societies' (Resilient Societies) request for rehearing of Order No. 797. The Commission stated that the rehearing

[18] *Id.*

[19] *Reliability Standard for Geomagnetic Disturbance Operations*, Order No. 797, 79 FR 35,911 (June 25, 2014), 147 FERC ¶ 61,209, *reh'g denied*, Order No. 797-A, 149 FERC ¶ 61,027 (2014).

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request "addressed a later stage of efforts on geomagnetic disturbances (i.e., NERC's future filing of Second Stage GMD Reliability Standards) and [that Resilient Societies] may seek to present those arguments at an appropriate time in response to that filing."[20] In particular, the Commission stated that GIC monitoring requirements should be addressed in the Second Stage GMD Reliability Standards.[21]

E. NERC Petition and Proposed Reliability Standard TPL-007-1

12. On January 21, 2015, NERC petitioned the Commission to approve proposed Reliability Standard TPL-007-1 and its associated violation risk factors and violation severity levels, implementation plan, and effective dates.[22] NERC also submitted a proposed definition for the term "Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment" for inclusion in the NERC Glossary. NERC maintains that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC further contends that the proposed

[20] Order No. 797-A, 149 FERC ¶ 61,027 at P 2.

[21] *Id.* P 27 (stating that the Commission continues "to encourage NERC to address the collection, dissemination, and use of geomagnetic induced current data, by NERC, industry or others, in the Second Stage GMD Reliability Standards because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models").

[22] Proposed Reliability Standard TPL-007-1 is not attached to this notice of proposed rulemaking (NOPR). The proposed Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM15-11-000 and on the NERC website, www.nerc.com. NERC submitted an errata on February 2, 2015 containing a corrected version of Exhibit A (Proposed Reliability Standard TPL-007-1).

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Reliability Standard satisfies the directive in Order No. 779 corresponding to the Second Stage GMD Reliability Standards.[23]

13. NERC states that proposed Reliability Standard TPL-007-1 applies to planning coordinators, transmission planners, transmission owners and generation owners who own or whose planning coordinator area or transmission planning area includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher. NERC explains that the applicability criteria for qualifying transformers in the proposed Reliability Standard is the same as that for the First Stage GMD Reliability Standard in EOP-010-1, which the Commission approved in Order No. 797.

14. The proposed Reliability Standard contains seven requirements.

15. Requirement R1 requires planning coordinators and transmission planners to determine the individual and joint responsibilities in the planning coordinator's planning

[23] We note that Resilient Societies has submitted to NERC, pursuant to Section 8.0 of the NERC Standards Process Manual, an appeal alleging certain procedural errors in the development of proposed Reliability Standard TPL-007-1. *See* NERC Rules of Procedure, Attachment 3A (Standards Process Manual), Section 8.0 (Process for Appealing an Action or Inaction). The appeal is currently pending NERC action. On May 12, 2015, Resilient Societies submitted a request for stay of the proceedings in Docket No. RM15-11-000, asking that the Commission refrain from issuing a notice of proposed rulemaking until NERC acts on Resilient Societies' appeal. We deny Resilient Societies' request. We see no irreparable harm in issuing a proposal for public comment as we do today. Rather, we will consider any necessary issues pertaining to the appeal before or in a final rule issued in this proceeding.

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area for maintaining models and performing studies needed to complete the GMD Vulnerability Assessment required in Requirement R4.[24]

16. Requirement R2 requires planning coordinators and transmission planners to maintain system models and GIC system models needed to complete the GMD Vulnerability Assessment required in Requirement R4.

17. Requirement R3 requires planning coordinators and transmission planners to have criteria for acceptable system steady state voltage limits for their systems during the benchmark GMD event described in Attachment 1 (Calculating Geoelectric Fields for the Benchmark GMD Event).

18. Requirement R4 requires planning coordinators and transmission planners to conduct a GMD Vulnerability Assessment every 60 months using the benchmark GMD event described in Attachment 1 to the proposed Reliability Standard. The benchmark GMD event is based on a 1-in-100 year frequency of occurrence and is composed of four elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) a scaling factor to account for local geomagnetic latitude; (3) a scaling factor to account for local earth conductivity; and (4) a reference geomagnetic field time series or wave shape to facilitate time-domain

[24] Proposed Reliability Standard TPL-007-1, Requirements R2, R3, R4, R5, and R7 refer to planning coordinators and transmission planners as "responsible entities."

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analysis of GMD impact on equipment.[25] The product of the first three elements is referred to as the regional geoelectric field peak amplitude.[26]

19. Requirement R5 requires planning coordinators and transmission planners to provide GIC flow information, to be used in the transformer thermal impact assessment required in Requirement R6, to each transmission owner and generator owner that owns an applicable transformer within the applicable planning area.

20. Requirement R6 requires transmission owners and generator owners to conduct thermal impact assessments on solely and jointly owned applicable transformers where the maximum effective GIC value provided in Requirement R5 is 75 amperes per phase (A/phase) or greater.

21. Requirement R7 requires planning coordinators and transmission planners to develop corrective action plans if the GMD Vulnerability Assessment concludes that the system does not meet the performance requirements in Table 1 (Steady State Planning Events).

II. Discussion

22. Pursuant to section 215(d) of the FPA, the Commission proposes to approve Reliability Standard TPL-007-1 as just, reasonable, not unduly discriminatory or

[25] *See* Proposed Reliability Standard TPL-007-1, Att. 1; s*ee also* NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

[26] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

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preferential, and in the public interest. The proposed Reliability Standard addresses the directives in Order No. 779 corresponding to the development of the Second Stage GMD Reliability Standards. Proposed Reliability Standard TPL-007-1 does this by requiring applicable Bulk-Power System owners and operators to conduct initial and on-going vulnerability assessments regarding the potential impact of a benchmark GMD event on the Bulk-Power System as a whole and on Bulk-Power System components.[27] In addition, the proposed Reliability Standard requires applicable entities to develop and implement corrective action plans to mitigate any identified vulnerabilities.[28] Potential mitigation strategies identified in the proposed Reliability Standard include, but are not limited to, among other things, the installation, modification, or removal of transmission and generation facilities and associated equipment.[29] Accordingly, proposed Reliability Standard TPL-007-1 constitutes an important step in addressing the risks posed by GMD events to the Bulk-Power System.

23. While proposed Reliability Standard TPL-007-1 addresses the Order No. 779 directives, pursuant to FPA section 215(d)(5), the Commission proposes to direct NERC to develop modifications to the Reliability Standard concerning: (1) the calculation of the reference peak geoelectric field amplitude component of the benchmark GMD event

[27] *See* Order No. 779, 143 FERC ¶ 61,147 at PP 67, 71.

[28] *Id.* P 79.

[29] *Id.*

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definition; (2) the collection of GIC monitoring and magnetometer data; and (3) deadlines for completing corrective action plans and the mitigation measures called for in corrective action plans. In addition, to improve the understanding of GMD events generally and address the specific research areas discussed below, the Commission proposes to direct that NERC submit informational filings. These proposals are discussed in greater detail below.

24. The Commission seeks comments from NERC and interested entities on these proposals.

A. Benchmark GMD Event Definition

NERC Petition

25. NERC states that the purpose of the benchmark GMD event is to "provide a defined event for assessing system performance during a low probability, high magnitude GMD event."[30] NERC explains that the benchmark GMD event represents "the most severe GMD event expected in a 100-year period as determined by a statistical analysis of recorded geomagnetic data."[31] The benchmark GMD event definition is used in the GMD Vulnerability Assessments and thermal impact assessment requirements of the proposed Reliability Standard.

[30] NERC Petition at 15.

[31] *Id.*

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26. As noted above, NERC states that the benchmark GMD event definition has four elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) a scaling factor to account for local geomagnetic latitude; (3) a scaling factor to account for local Earth conductivity; and (4) a reference geomagnetic field time series or wave shape to facilitate time-domain analysis of GMD impact on equipment.[32]

27. The standard drafting team determined that a 1-in-100 year GMD event would cause an 8 V/km reference peak geoelectric field amplitude at 60 degree geomagnetic latitude using Québec's earth conductivity.[33] The standard drafting team stated that:

> the reference geoelectric field amplitude was determined through statistical analysis using … field measurements from geomagnetic observatories in northern Europe and the reference (Quebec) earth model …. The Quebec earth model is generally resistive and the geological structure is relatively well understood. The statistical analysis resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km …. The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years.[34]

28. The standard drafting team explained that it used field measurements taken from the IMAGE magnetometer chain, which covers Northern Europe, for the period 1993-2013 to calculate the reference peak geoelectric field amplitude used in the benchmark

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[32] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

[33] *Id.*

[34] *Id.* (footnotes omitted).

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GMD event definition.[35] As described in NERC's petition, the standard drafting team "spatially averaged" four different station groups of IMAGE data, each spanning a square area of approximately 500 km (roughly 310 miles) in width.[36] The standard drafting team justified the use of spatial averaging by stating that the proposed Reliability Standard is designed to "address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse."[37]

29. NERC states that the benchmark GMD event includes scaling factors to enable applicable entities to tailor the reference peak geoelectric field to their specific location for conducting GMD Vulnerability Assessments. NERC states that the scaling factors in the benchmark GMD event definition are applied to the reference peak geoelectric field

[35] *Id.* at 8. The International Monitor for Auroral Geomagnetic Effects (IMAGE) consists of 31 magnetometer stations in northern Europe maintained by 10 institutes from Estonia, Finland, Germany, Norway, Poland, Russia, and Sweden. *See* IMAGE website, *available at* http://space.fmi.fi/image/beta/?page=home#.

[36] As applied by the standard drafting team, spatial averaging refers to the averaging of geoelectric field amplitude readings within a given area. NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 9.

[37] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 9.

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amplitude to adjust the 8 V/km value for different geomagnetic latitudes and earth conductivities.[38]

30. The standard drafting team also identified a reference geomagnetic field time series from an Ottawa magnetic observatory during a 1989 GMD event that affected Québec.[39] The standard drafting team used this time series to estimate a geoelectric field, represented as a time series (i.e., 10-second values over a period of days), that is expected to occur at 60 degree geomagnetic latitude during a 1-in-100 year GMD event. NERC explains that this time series is used to facilitate time-domain analysis of GMD impacts on equipment.[40]

Discussion

31. The Commission proposes to approve proposed Reliability Standard TPL-007-1, including the proposed benchmark GMD event definition submitted by NERC. However, pursuant to FPA section 215(d)(5) , the Commission proposes to direct that NERC develop modifications to the benchmark GMD event definition set forth in Attachment 1 of the proposed Reliability Standard so that the definition is not based solely on spatially-averaged data. The Commission also seeks comment from NERC and other interested entities regarding the scaling factor used to account for geomagnetic

[38] NERC Petition at 18-19.

[39] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 15-16.

[40] *Id.* at 5-6.

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latitude in the benchmark GMD event definition. The Commission also proposes to direct NERC to submit a work plan, and subsequently one or more informational filings, that address the specific issues discussed below.

32. The benchmark GMD event definition proposed by NERC complies with the directive in Order No. 779 requiring that the Second Stage GMD Reliability Standards identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System. Order No. 779 did not specify the severity of the storm or define the characteristics of the benchmark GMD event. Instead, the Commission directed NERC, through the standards development process, to define the benchmark GMD events. Consistent with the guidance provided in Order No. 779, the benchmark GMD event definition proposed by NERC addresses the potential widespread impact of a severe GMD event, while taking into consideration the variables of geomagnetic latitude and local earth conductivity.[41] Accordingly, we propose to approve the definition submitted by NERC. Nonetheless, while acceptable as consistent with FPA section 215 and the Order No. 779 directives, we believe that the

[41] *See* Order No. 779, 143 FERC ¶ 61,147 at P 71 ("the benchmark GMD events should be based on factors that may include, but are not limited to, varying severity of the GMD … duration, geographic footprint of the GMD, how the GMD's intensity varies with latitude, system configuration, and the orientation of the magnetic fields produced by the GMD); *see also id*. P 70 ("[GMD] vulnerability assessments would be based on uniform criteria (e.g., geographic location and geology) but the values for such criteria would be entity-specific").

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benchmark GMD event definition should be improved through the proposed revision and research discussed below.

33. First, the proposed Reliability Standard's exclusive use of spatial averaging to calculate the reference peak geoelectric field amplitude could underestimate the impact of a 1-in-100 year GMD event, which was the design basis arrived upon by the standard drafting team. NERC states that the benchmark GMD event "expands upon work conducted by the NERC GMD Task Force in which 1-in 100 year geoelectric field amplitudes were calculated from a well-known source of dense high-resolution geomagnetic data commonly used in space weather research [i.e., IMAGE data]."[42] However, the application of spatial averaging significantly reduces the reference peak geoelectric field amplitude using the IMAGE data compared with a prior analysis of nearly the same data set. As noted in the NERC petition, the GMD Interim Report described a study that used the same IMAGE magnetometers and data as the standard drafting team for the period 1993-2006.[43] That study calculated a 1-in-100 year peak geoelectric amplitude of 20 V/km for Québec.[44] The study calculated a significantly higher figure (20 V/km versus 8 V/km) using similar data as the standard drafting team because, instead of averaging geoelectric field values occurring simultaneously over a

[42] NERC Petition at 17.

[43] GMD Interim Report at 22.

[44] *Id.*

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large geographic area, the study cited by the GMD Interim Report used the magnitude of the geoelectric amplitude in individual geomagnetic observatories.

34. Based on our review of NERC's petition, it does not appear that spatial averaging of geomagnetic fields is discussed in the studies cited by the standard drafting team except in the standard drafting team's GMD Benchmark Event White Paper. In addition, it is unclear how the standard drafting team determined that spatial averaging should be performed using a square area 500 km in width. The GMD Benchmark Event White Paper explains that the IMAGE magnetometers were organized into four groups comprised of squares 500 km wide, and the readings within a group were averaged. The GMD Benchmark Event White Paper also states, citing to the statistical analysis in its Appendix I, that "geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system."[45] While Appendix I of the GMD Benchmark Event White Paper discusses why local geomagnetic disturbances do not have a significant impact on all transformers operating within a square 500 km in width, it does not explain why the standard drafting team chose a square area 500 km in width as opposed to a square with a smaller or larger total area. These questions largely inform our concerns regarding the proposed Reliability Standard's heavy reliance on spatial averaging.

[45] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 4.

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35. The geoelectric field values used to conduct GMD Vulnerability Assessments and thermal impact assessments should reflect the real-world impact of a GMD event on the Bulk-Power System and its components. A GMD event will have a peak value in one or more location(s), and the amplitude will decline over distance from the peak. Only applying a spatially-averaged geoelectric field value across an entire planning area would distort this complexity and could underestimate the contributions caused by damage to or misoperation of Bulk-Power System components to the system-wide impact of a GMD event within a planning area. However, imputing the highest peak geoelectric field value in a planning area to the entire planning area may incorrectly overestimate GMD impacts. Neither approach, in our view, produces an optimal solution that captures physical reality.

36. To address this issue, the Commission proposes to direct NERC to develop modifications to the Reliability Standard so that the reference peak geoelectric field amplitude element of the benchmark GMD event definition is not based solely on spatially-averaged data. For example, NERC could satisfy this proposal by revising the Reliability Standard to require applicable entities to conduct GMD Vulnerability Assessments and thermal impact assessments using two different benchmark GMD events: the first benchmark GMD event using the spatially-averaged reference peak geoelectric field value (8 V/km) and the second using the non-spatially averaged peak

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geoelectric field value found in the GMD Interim Report (20 V/km).[46] The revised Reliability Standard could then require applicable entities to take corrective actions, using engineering judgment, based on the results of both assessments. That is, the applicable entity would not always be required to mitigate to the level of risk identified by the non-spatially averaged analysis; instead, the selection of mitigation would reflect the range of risks bounded by the two analyses, and be based on engineering judgment within this range, considering all relevant information. This proposed revision is consistent with the directive in Order No. 779 that owners and operators develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System.[47] Alternatively, NERC could propose an equally efficient and effective modification that does not rely exclusively on the spatially-averaged reference peak geoelectric field value.[48]

[46] Conducting a GMD Vulnerability Assessment using essentially two measures of the same benchmark GMD events is consistent with Order No. 779 because, in that order, the Commission contemplated that an applicable entity could be required to assess GMD vulnerabilities using multiple benchmark GMD events. Order No. 779, 143 FERC ¶ 61,147 at P 2 ("The Second Stage GMD Reliability Standards must identify 'benchmark GMD events' that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System.").

[47] Order No. 779, 143 FERC ¶ 61,147 at P 2.

[48] For example, responsible entities could calculate GIC flows and resulting Bulk-Power System impacts using models that utilize both spatially averaged and non-spatially averaged peak geoelectric field values to simulate GMD conditions.

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37. The Commission also seeks comment from NERC and other interested entities regarding the scaling factor used in the benchmark GMD event definition to account for differences in geomagnetic latitude. Specifically, the Commission seeks comment on whether, in light of studies indicating that GMD events could have pronounced effect on lower geomagnetic latitudes, a modification is warranted to reduce the impact of the scaling factors.[49]

38. Next, the record submitted by NERC and other available information manifests a need for more data and certainty in the knowledge and understanding of GMD events and their potential effect on the Bulk-Power System. For example, NERC's proposal is based on data from magnetometers in northern Europe, from a relatively narrow timeframe with relatively low solar activity, and with little or no data on concurrent GIC flows. Similarly, the adjustments for latitude and ground conductivity are based on the limited information currently available, but additional data-gathering is needed. To address this

[49] *See*, *e.g.*, Ngwira, C. M., Pulkkinen, A., Kuznetsova, M. M., Glocer, A., "Modeling extreme 'Carrington-type' space weather events using three-dimensional global MHD simulations," 119 Journal of Geophysical Research: Space Physics 4472 (2014) (finding that in Carrington-type events "the region of large induced ground electric fields is displaced further equatorward … [and] thereby may affect power grids … such as [those in] southern states of [the] continental U.S."); Gaunt, C. T., Coetzee, G., "Transformer Failures in Regions Incorrectly Considered to have Low GIC-Risk," 2007 IEEE Lausanne 807 (July 2007) (stating that twelve transformers were damaged and taken out of service in South Africa (at -40 degrees latitude) during a 2003 GMD event).

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limitation on relevant information, we propose to direct that NERC conduct or oversee additional analysis on these issues.[50]

39. In particular, we propose to direct that NERC submit informational filings that address the issues discussed below. In the first informational filing, NERC should submit a work plan indicating how NERC plans to: (1) further analyze the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km); (2) further analyze earth conductivity models by, for example, using metered GIC and magnetometer readings to calculate earth conductivity and using 3-D readings; (3) determine whether new analyses and observations support modifying the use of single station readings around the earth to adjust the spatially averaged benchmark for latitude; and (4) assess how to make GMD data (e.g., GIC monitoring and magnetometer data) available to researchers for study.[51] We propose that NERC submit the work plan within six months of the effective date of a final rule in this proceeding. The work plan submitted by NERC should include a schedule to submit one or more informational

[50] *See, e.g., Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208 (2013) (approving Reliability Standard but directing that NERC perform a study to develop empirical evidence on one input to the "Gallet equation" used to calculate minimum clearances for vegetation).

[51] The Commission seeks comment on the barriers, if any, to public dissemination of GIC and magnetometer readings, including if the dissemination of such data poses a security risk and if any such data should be treated as Critical Energy Infrastructure Information or otherwise restricted to authorized users.

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filings that apprise the Commission of the results of the four additional study areas as well as any other relevant developments in GMD research. Further, in the submissions, NERC should assess whether the proposed Reliability Standard remains valid in light of new information or whether revisions are appropriate.

B. Thermal Impact Assessments

NERC Petition

40. Proposed Reliability Standard TPL-007-1, Requirement R6 requires owners of transformers that are subject to the proposed Reliability Standard to conduct thermal analyses to determine if the transformers would be able to withstand the thermal effects associated with a benchmark GMD event. NERC states that transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 75 A/phase during the benchmark GMD event as determined by an analysis of the system. NERC explains that "based on available power transformer measurement data, transformers with an effective GIC of less than 75 A per phase during the Benchmark GMD Event are unlikely to exceed known temperature limits established by technical organizations."[52]

41. As provided in Requirements R5 and R6, "the maximum GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1" determines whether a transformer satisfies the 75 A/phase threshold. If the 75

[52] NERC Petition at 30.

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A/phase threshold is satisfied, Requirement R6 states, in relevant part, that a thermal impact assessment should be conducted on the qualifying transformer based on the effective GIC flow information provided in Requirement R5.

Discussion

42. The Commission proposes to approve proposed Reliability Standard TPL-007-1, Requirement R6. However, the Commission has two concerns regarding the proposed thermal impact assessment in Requirement R6. These concerns reflect in part the difficulty of replacing large transformers quickly, as reflected in studies, such as an April 2014 report by the Department of Energy that highlighted the reliance in the United States on foreign suppliers for large transformers.[53]

43. First, as discussed in the previous section, the Commission proposes to direct NERC to develop modifications to the Reliability Standard such that the benchmark GMD event definition's reference peak geoelectric field amplitude element does not rely on spatially-averaged data alone. The proposed modification is relevant to thermal impact assessments, as it is relevant to GMD Vulnerability Assessments, because both are ultimately predicated on the benchmark GMD event definition. Indeed, the concern is even greater in this context because a thermal impact assessment assesses the localized

[53] U.S. Department of Energy, Large Power Transformers and the U.S. Electric Grid (April 2014), *available at* http://energy.gov/sites/prod/files/2014/04/f15/LPTStudyUpdate-040914.pdf

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impact of a GMD event on an individual transformer. Thus, we propose to direct NERC to modify the Reliability Standard to require responsible entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments.

44. Second, Requirements R5.1 and R6 provide that the geoelectric field orientation causing the maximum effective GIC value in each transformer should be used to determine if the assessed transformer satisfies the 75 A/phase qualifying threshold in Requirement R6. However, Requirement R6 does not use the maximum GIC-producing orientation to conduct the thermal assessment for qualifying transformers (i.e., transformers with an maximum effective GIC value greater than 75A/phase). Instead, Requirement R6 uses the effective GIC time series described in Requirement R5.2 to conduct the thermal assessment on qualifying transformers.[54] The Commission seeks comment from NERC as to why qualifying transformers are not assessed for thermal impacts using the maximum GIC-producing orientation. NERC should address whether, by not using the maximum GIC-producing orientation, the required thermal impact assessments could underestimate the impact of a benchmark GMD event on a qualifying transformer.

[54] *See also* NERC Petition, Ex. E (White Paper on Transformer Thermal Impact Assessment) at 8-9.

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C. Monitoring Devices

NERC Petition

45. Proposed Reliability Standard TPL-007-1, Requirement R2 requires responsible entities to "maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s)." NERC states that proposed Reliability Standard TPL-007-1 contains "requirements to develop the models, studies, and assessments necessary to build a picture of overall GMD vulnerability and identify where mitigation measures may be necessary."[55] NERC explains that mitigating strategies "may include installation of hardware (e.g., GIC blocking or monitoring devices), equipment upgrades, training, or enhanced Operating Procedures."[56]

Discussion

46. The Commission proposes to direct NERC to develop revisions to Reliability Standard TPL-007-1 requiring installation of monitoring equipment (i.e., GIC monitors and magnetometers) to the extent there are any gaps in existing GIC monitoring and magnetometer networks, which will ensure a more complete set of data for planning and operational needs. Alternatively, we seek comment on whether NERC itself should be responsible for installation of any additional, necessary magnetometers while affected

[55] NERC Petition at 13.

[56] *Id.* at 32.

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entities would be responsible for installation of additional, necessary GIC monitors. As part of NERC's work plan, we propose to direct that NERC identify the number and location of current GIC monitors and magnetometers in the United States to assess whether there are any gaps.

47. NERC maintains that the installation of monitoring devices could be part of a mitigation strategy. We agree with NERC regarding the importance of GIC and magnetometer data. As the Commission stated in Order No. 779, the tools for assessing GMD vulnerabilities are not fully mature.[57] Data from monitors are needed to validate the analyses underlying NERC's proposed Reliability Standard and the analyses to be performed by affected entities.[58] GIC monitors also can facilitate real-time adjustments to grid operations during GMD events, to maintain reliability and prevent significant equipment damage, by enhancing situational awareness for grid operators. For example, PJM's operating procedures for GMDs are triggered when GICs are above 10 A for 10 minutes at either of two specified locations, and confirmed by other sources of information.[59]

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[57] Order No. 779, 143 FERC ¶ 61,147 at P 68.

[58] *See*, *e.g.*, *Disturbance Monitoring and Reporting Requirements Reliability Standard*, 80 FR 22,441 (Apr. 16, 2015), 151 FERC ¶ 61,042 (2015) (notice of proposed rulemaking proposing to approve Reliability Standard PRC-002-2 requiring the collection of disturbance monitoring data).

[59] *See* PJM Manual 13 (Emergency Operations), Revision 57, at 55 (2015).

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48. Accordingly, rather than wait to install necessary monitoring devices as part of a corrective action plan, GIC and magnetometer data should be collected by applicable entities at the outset to validate and improve system models and GIC system models, as well as improve situational awareness. To be clear, we are not proposing that every transformer would need its own GIC monitor or that every entity would need its own magnetometer. Instead, we are proposing the installation and collection of data from GIC monitors and magnetometers in enough locations to provide adequate analytical validation and situational awareness. We propose that NERC's work plan use this criterion in assessing the need and locations for GIC monitors and magnetometers.

49. Cost recovery is potentially available for costs associated with or incurred to comply with proposed Reliability Standard TPL-007-1, including for the purchase and installation of monitoring devices.[60] The Commission seeks comment on whether it should adopt a policy specifically allowing recovery of these costs.

[60] Order No. 779, 143 FERC ¶ 61,147 at P 14 n.20 (stating that "nothing precludes entities from seeking cost recovery if needed"); *see Extraordinary Expenditures Necessary to Safeguard National Energy Supplies*, 96 FERC ¶ 61,299, at 61,129 (2001) (stating that the Commission "will approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure in response to the heightened state of alert. Companies may propose a separate rate recovery mechanism, such as a surcharge to currently existing rates or some other cost recovery method"); *see also Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052, at P 28 (2004) (affirming and clarifying that "the policy extends to the recovery of prudent reliability expenditures, including those for vegetation management, improved grid management and monitoring equipment, operator training and compliance with NERC standards").

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D. Corrective Action Plan Deadlines

NERC Petition

50. Proposed Reliability Standard TPL-007-1, Requirement R7 provides that:

> Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that their System does not meet the performance requirements of Table 1 shall develop a Corrective Action Plan addressing how the performance requirements will be met ….

NERC explains that the NERC Glossary defines corrective action plan to mean, "A list of actions and an associated timetable for implementation to remedy a specific problem."[61] Requirement R7.3 states that the corrective action plan shall be provided within "90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need."

Discussion

51. The Commission proposes to direct that NERC revise Reliability Standard TPL-007-1 to include deadlines concerning the development and implementation of corrective action plans under Requirement R7.

52. In accordance with Order No. 779 directives, Requirement R7 requires applicable entities to develop and implement measures when vulnerabilities from a benchmark

[61] NERC Petition at 31.

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GMD event are identified.[62] However, Requirement R7 does not establish deadlines for developing or implementing corrective action plans. Requirement R7 only requires responsible entities to distribute corrective action plans within 90 days of completion to certain registered entities. By contrast, other NERC Reliability Standards include deadlines for developing corrective action plans, such as Reliability Standard PRC-006-2 (Automatic Underfrequency Load Shedding) and Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements). In addition, by definition, a corrective action plan includes "an associated timetable for implementation" of a remedy.[63] Consistent with the definition of corrective action plan and the other NERC Reliability Standards, the Commission proposes to direct that NERC modify Reliability Standard TPL-007-1 to require corrective action plans to be developed within one year of the completion of the GMD Vulnerability Assessment.

53. A corrective action plan is defined in the NERC Glossary as "[a] list of actions and an associated timetable for implementation to remedy a specific problem." Because of the complexities surrounding GMDs and the uncertainties about mitigation techniques, the time needed to implement a corrective action plan may be difficult to determine. At

[62] Order No. 779, 143 FERC ¶ 61,147 at P 2 ("If the assessments identify potential impacts from benchmark GMD events, the Reliability Standards *should* require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event.").

[63] NERC Glossary at 26.

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the same time, the absence of reasonable deadlines for completion of corrective actions may risk significant delay before identified corrective actions are started or finished. The Commission, therefore, proposes to direct NERC to modify the Reliability Standard to require a deadline for non-equipment mitigation measures that is two years following development of the corrective action plan and a deadline for mitigation measures involving equipment installation that is four years following development of the corrective action plan. The Commission recognizes that there is little experience with installing equipment for GMD mitigation and thus we are open to proposals that may differ from our proposal, particularly from any entities with experience in this area.

54. We seek comments from NERC and interested entities on these proposals. Further, we seek comment on appropriate alternative deadlines and whether there should be a mechanism that would allow NERC to consider, on a case-by-case basis, requests for extensions of required deadlines.

E. Minimization of Load Loss and Curtailment

NERC Petition

55. Proposed Reliability Standard TPL-007-1, Requirement R4 states that each responsible entity "shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months." Requirement R4.2 further states that the "study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1."

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56. NERC maintains that Table 1 sets forth requirements for system steady state performance. NERC explains that Requirement R4 and Table 1 "address assessments of the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the loss of devices due to GIC impacts."[64] Table 1 provides, in relevant part, that load loss and/or curtailment are permissible elements of the steady state:

> Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Discussion

57. The Commission seeks comment from NERC regarding the provision in Table 1 that "Load loss or curtailment of Firm Transmission Service should be minimized." Because the term "minimized" does not represent an objective value, the provision is potentially subject to interpretation and assertions that the term is vague and may not be enforceable. Similarly, use of the modifier "should" might indicate that minimization of load loss or curtailment is only an expectation or a guideline rather than a requirement.

58. The Commission seeks comment from NERC that explains how the provision in Table 1 regarding load loss and curtailment will be enforced, including: (1) whether, by

[64] NERC Petition at 39.

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using the term "should," Table 1 requires minimization of load loss or curtailment, or both; and (2) what constitutes "minimization" and how it will be assessed.

F. Violation Risk Factors and Violation Severity Levels

59. Each requirement of proposed Reliability Standard TPL-007-1 includes one violation risk factor and has an associated set of at least one violation severity level. NERC states that the ranges of penalties for violations will be based on the sanctions table and supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines.

60. The Commission proposes to approve the violation risk factors and violation severity levels submitted by NERC, for the requirements in Reliability Standard TPL-007-1, consistent with the Commission's established guidelines.[65]

G. Implementation Plan and Effective Dates

61. NERC proposes a phased, five-year implementation period.[66] NERC maintains that the proposed implementation period is necessary: (1) to allow time for entities to develop the required models; (2) for proper sequencing of assessments because thermal impact assessments are dependent on GIC flow calculations that are determined by the responsible planning entity; and (3) to give time for development of viable corrective action plans, which may require applicable entities to "develop, perform, and/or validate

[65] *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

[66] NERC Petition, Ex. B (Implementation Plan for TPL-007-1).

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new or modified studies, assessments, procedures … [and because] [s]ome mitigation measures may have significant budget, siting, or construction planning requirements."[67]

62. The proposed implementation plan states that Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after Commission approval. For Requirement R2, NERC proposes that the requirement shall become effective on the first day of the first calendar quarter that is 18 months after Commission approval. NERC proposes that Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after Commission approval. NERC proposes that Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after Commission approval. And for Requirement R3, Requirement R4, and Requirement R7, NERC proposes that the requirements shall become effective on the first day of the first calendar quarter that is 60 months after Commission approval.

63. The Commission proposes to approve the implementation plan and effective dates submitted by NERC. However, given the serial nature of the requirements in the proposed Reliability Standard, we are concerned about the duration of the timeline associated with any mitigation stemming from a corrective action plan. As a result, the Commission seeks comment from NERC and other interested entities as to whether the length of the implementation plan, particularly with respect to Requirements R4, R5, R6, and R7, could be reasonably shortened.

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[67] *Id.* at 2.

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III. Information Collection Statement

64. The collection of information contained in this notice of proposed rulemaking is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[68] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[69]

65. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

66. We solicit comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically, the Commission asks that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

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[68] 44 U.S.C. 3507(d).

[69] 5 CFR 1320.11 (2014).

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Public Reporting Burden: The Commission proposes to approve Reliability Standard TPL-007-1 and the associated implementation plan, violation severity levels, and violation risk factors, as discussed above. Proposed Reliability Standard TPL-007-1 will impose new requirements for transmission planners, planning coordinators, transmission owners, and generator owners. Proposed Reliability Standard TPL-007-1, Requirement R1 requires planning coordinators, in conjunction with transmission planner, to identify the responsibilities of the planning coordinator and transmission planner in the planning coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessments. Proposed Requirements R2, R3, R4, R5, and R7 refer to the "responsible entity, as determined by Requirement R1," when identifying which applicable planning coordinators or transmission planners are responsible for maintaining models and performing the necessary study or studies. Proposed Requirement R2 requires that the responsible entities maintain models for performing the studies needed to complete GMD Vulnerability Assessments, as required in proposed Requirement R4. Proposed Requirement R3 requires responsible entities to have criteria for acceptable system steady state voltage performance during a benchmark GMD event. Proposed Requirement R4 requires responsible entities to complete a GMD Vulnerability Assessment of the near-term transmission planning horizon once every 60 calendar months. Proposed Requirement R5 requires responsible entities to provide GIC flow information to transmission owners and generator owners that own an applicable bulk electric system power transformer in the planning area. This information is necessary for applicable transmission owners and generator owners to conduct the

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thermal impact assessments required by proposed Requirement R6. Proposed Requirement R6 requires applicable transmission owners and generator owners to conduct thermal impact assessments where the maximum effective GIC value provided in proposed Requirement R5, Part 5.1 is 75 A/phase or greater. Proposed Requirement R7 requires responsible entities to develop a corrective action plan when its GMD Vulnerability Assessment indicates that its system does not meet the performance requirements of Table 1 – Steady State Planning Events. The corrective action plan must address how the performance requirements will be met, must list the specific deficiencies and associated actions that are necessary to achieve performance, and must set forth a timetable for completion. The Commission estimates the annual reporting burden and cost as follows:

FERC-725N, as modified by the NOPR in Docket No. RM15-11-000 (TPL-007-1 Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events)[70]

[70] Eng.=engineer; RK =recordkeeping (record clerk); PC=planning coordinator; TP=transmission planner; TO=transmission owner; and GO=generator owner.

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	Number of Respondents (1)	Annual Number of Responses per Respondent (2)	Total Number of Responses (1)*(2)=(3)	Average Burden Hours & Cost Per Response [71] (4)	Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)	Cost per Respondent ($) (5)÷(1)
(One-time) Requirement 1	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 4 hrs. ($149.80)	1,089 hrs. (605 Eng., 484 RK); $58,267.55 ($40,141.75 Eng., $18,125.80 RK)	$481.55
(On-going) Requirement 1	121 (PC & TP)	1	121	Eng. 3 hrs. ($199.05); RK 2 hrs. ($74.90)	605 hrs. (363 Eng., 242 RK); $33,147.95 ($24,085.05 Eng., $9,062.90 RK)	$273.95

[71] The estimates for cost per response are derived using the following formula: Burden Hours per Response * $/hour = Cost per Response. The $66.35/hour figure for an engineer and the $37.45/hour figure for a record clerk are based on data on the average salary plus benefits from the Bureau of Labor Statistics obtainable at **Error! Hyperlink reference not valid.**http://bls.gov/ oes/current/naics3_221000.htm and http://www.bls.gov/news.release/ecec.nr0.htm.

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(One-time) Requirement 2	121 (PC & TP)	1	121	Eng. 22 hrs. ($1,459.70); RK 18 hrs. ($674.10)	4840 hrs. (2,662 Eng., 2,178 RK); $258,189.80 ($176,623.70 Eng., $81,566.10 RK)	$2,133.80
(On-going) Requirement 2	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 3 hrs. ($112.35)	968 hrs. (605 Eng., 363 RK); $53,736.10 ($40,141.75 Eng., $13,594.35 RK)	$444.10
(One-time) Requirement 3	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 3 hrs. ($112.35)	968 hrs. (605 Eng., 363 RK); $53,736.10 ($40,141.75 Eng., $13,594.35 RK)	$444.10
(On-going) Requirement 3	121 (PC & TP)	1	121	Eng. 1 hrs. ($66.35); RK 1 hrs. ($37.45)	242 hrs. (121 Eng., 121 RK); $12,559.80 ($8,028.35 Eng., $4,531.45 RK)	$103.80

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(On-going) Requirement 4	121 (PC & TP)	1	121	Eng. 27 hrs. ($1,791.45); RK 21 hrs. ($786.45)	5,808 hrs. (3,267 Eng., 2,541 RK); $311,919.85 ($216,765.45 Eng., $95,154.40 RK)	$2,277.85
(On-going) Requirement 5	121 (PC & TP)	1	121	Eng. 9 hrs. ($597.15); RK 7 hrs. ($262.15)	1936 hrs. (1,089 Eng., 847 RK); $103,975.30 ($72,255.15 Eng., $31,720.15 RK)	$859.30
(One-time) Requirement 6	881 (TO & GO)	1	881	Eng. 22 hrs. ($1,459.70); RK 18 hrs. ($674.19)	35,240 hrs. (19,382 Eng., 15,858 RK); $1,879,957.09 ($1,285,995.70 Eng., $593,961.39 RK)	$2,133.89
(On-going) Requirement 6	881 (TO & GO)	1	881	Eng. 2 hrs. ($132.70); RK 2 hrs. ($74.90)	3,524 hrs. (1,762 Eng., 1762 RK); $182,895.60 ($116,908.70 Eng., $65,986.90 RK)	$207.60

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(On-going) Requirement 7	121 (PC & TP)	1	121	Eng. 11 hrs. ($729.85); RK 9 hrs. ($337.05)	2,420 hrs. (1,331 Eng., 1,089 RK); $129,094.90 ($88,311.85 Eng., $40,783.05 RK)	$1,066.90
TOTAL			**2851**		**57,640[72] hrs. (31,792 Eng., 25,848 RK); $3,077,480.04 ($2,109,399.20 Eng., $968,080.84 RK)**	

Title: FERC-725N, Mandatory Reliability Standards: TPL Reliability Standards

Action: Proposed Additional Requirements.

OMB Control No: 1902-0264.

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: One time and on-going.

Necessity of the Information: The Commission has reviewed the requirements pertaining to proposed Reliability Standard TPL-007-1 and has made a determination that the

[72] Of the 57,640 total burden hours, 42,137 hours are one time burden hours, and 15,503 hours are on-going annual burden hours.

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proposed requirements of this Reliability Standard are necessary to implement section 215 of the FPA. Specifically, these requirements address the threat posed by GMD events to the Bulk-Power System and conform to the Commission's directives regarding development of the Second Stage GMD Reliability Standards, as set forth in Order No. 779.

Internal review: The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

67. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

68. Comments concerning the information collections proposed in this notice of proposed rulemaking and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference FERC-725N and OMB Control No. 1902-0264 in your submission.

IV. Environmental Analysis

69. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

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on the human environment.[73] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[74] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

70. The Regulatory Flexibility Act of 1980 (RFA)[75] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[76] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from a standard based on megawatt hours).[77] Under SBA's new size standards, planning coordinators, transmission planners,

[73] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

[74] 18 CFR 380.4(a)(2)(ii).

[75] 5 U.S.C. 601-12.

[76] 13 CFR 121.101.

[77] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77,343 (Dec. 23, 2013).

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transmission owners, and generator owners are likely included in one of the following categories (with the associated size thresholds noted for each):[78]

- Hydroelectric power generation, at 500 employees
- Fossil fuel electric power generation, at 750 employees
- Nuclear electric power generation, at 750 employees
- Other electric power generation (e.g., solar, wind, geothermal, biomass, and other), at 250 employees
- Electric bulk power transmission and control,[79] at 500 employees

71. Based on these categories, the Commission will use a conservative threshold of 750 employees for all entities.[80] Applying this threshold, the Commission estimates that there are 440 small entities that function as planning coordinators, transmission planners, transmission owners, and/or generator owners. However, the Commission estimates that only a subset of such small entities will be subject to the proposed Reliability Standard given the additional applicability criteria in the proposed Reliability Standard (i.e., to be subject to the requirements of the proposed Reliability Standard, the applicable entity must own or must have a planning area that contains a large power transformer with a high side, wye grounded winding with terminal voltage greater than 200 kV).

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[78] 13 CFR 121.201, Sector 22, Utilities.

[79] This category covers transmission planners and planning coordinators.

[80] By using the highest number threshold for all types of entities, our estimate conservatively treats more entities as "small entities."

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72. Proposed Reliability Standard TPL-007- 1 enhances reliability by establishing requirements that require applicable entities to perform GMD Vulnerability Assessments and to mitigate any identified vulnerabilities. The Commission estimates that each of the small entities to whom the proposed Reliability Standard TPL-007-1 applies will incur one-time compliance costs of $5,193.34 and annual ongoing costs of $5,233.50.

73. The Commission does not consider the estimated cost per small entity to impose a significant economic impact on a substantial number of small entities. Accordingly, the Commission certifies that the proposed Reliability Standard will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

74. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**. Comments must refer to Docket No. RM15-11-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

75. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

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76. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC, 20426.

77. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

78. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

79. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

80. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference

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Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

Kimberly D. Bose,
Secretary.

Document Content(s)

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151 FERC ¶ 61,175
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

Western Electricity Coordinating Council Docket No. IN14-11-000

ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued May 26, 2015)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) among the Office of Enforcement (Enforcement), the North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Peak Reliability (Peak). This order is in the public interest because it resolves on fair and reasonable terms an investigation of WECC (as the Reliability Coordinator (RC) for the Western Interconnection (WECC RC)), conducted by Enforcement in coordination with NERC and the Commission's Office of Electric Reliability (OER), into possible violations of Reliability Standards associated with WECC RC's oversight of a portion of the Bulk-Power System (BPS) and a blackout that occurred on September 8, 2011 (the September 8 event or the event). WECC agrees to pay a civil penalty of $16,000,000, of which $3,000,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $13,000,000 will be invested in reliability enhancement measures identified below that go above and beyond the Agreement's mitigation and reliability activities or what the Reliability Standards require (Reliability Enhancements). Peak did not exist as a separate entity at the time of the September 8 event, but is a party to the Agreement as the successor to WECC as the RC for the Western Interconnection. WECC and Peak also commit to certain mitigation and reliability activities, subject to compliance monitoring, as detailed in the Agreement.

I. Background

2. WECC is a non-profit, public service corporation and is not a load-serving entity. At the time of the event, WECC acted as both the Regional Entity (WECC RE) and the RC for the Western Interconnection. The WECC region at the time of the event extended from Canada to Mexico, was nearly 1.8 million square miles in size and served a population of 78 million. It included the Canadian provinces of Alberta and British Columbia, the northern part of Baja California, Mexico, the states of Washington,

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Oregon, California, Idaho, Nevada, Utah, Arizona, Colorado, Wyoming, and portions of Montana, South Dakota, New Mexico, and Texas.

3. WECC's RE and RC functions were organized separately, but reported to the same WECC executive management. WECC RC was a NERC Registered Entity, and was the highest level of authority responsible for the reliable operation of the Bulk Electric System (BES) in the Western Interconnection.

4. The RC of the Western Interconnection (formerly WECC RC, now Peak) is responsible for overseeing operation of the Western Interconnection in real time, receiving data from entities throughout the entire Interconnection, and providing high-level situational awareness for the entire system. The RC has the authority to prevent or mitigate emergency operating conditions in the next-day and real-time timeframes. The RC may issue directives to other functional entities to ensure reliable operations. The RC performs reliability analyses including next-day planning and real-time contingency analysis (RTCA) for the Western Interconnection. The RC may also assist transmission operators (TOPs) in mitigating equipment overloads and coordinating restoration plans, contingency plans, and reliability-related services.

5. As the RE, WECC or its delegate, among other things, monitors compliance of Registered Entities (including, formerly, WECC RC and currently, Peak) with the Reliability Standards, under delegated authority from NERC.

6. On March 16, 2007, in Order No. 693,[1] the Commission approved the initial Reliability Standards, which became mandatory and enforceable within the contiguous United States on June 18, 2007.

7. After the event, WECC sought approval from the Commission to establish a new entity to perform the RC and interchange authority (IA) functions in the Western Interconnection. The bifurcation of WECC into two separate entities, WECC and Peak, received final approval from the Commission on February 12, 2014.[2] With the Commission's approval, WECC sub-delegated the RC and IA functions in the Western Interconnection to Peak. WECC has retained its RE responsibilities.

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[1] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[2] *See North American Electric Reliability Corp.*, 146 FERC ¶ 61,092 (2014*), reh'g denied*, 147 FERC ¶ 61,064 (2014) (accepting compliance filings submitted by NERC and WECC and eliminating all final obstacles to bifurcation), appeal docketed *sub nom Edison Electric Institute v. FERC*, No. 14-1071 (D.C. Cir. May 9, 2014).

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8. WECC and Peak are subject to the Commission's regulation under section 215 of the Federal Power Act (FPA).[3]

9. The investigation of WECC arose out of a system disturbance that occurred on the afternoon of September 8, 2011 in the Pacific Southwest, which resulted in cascading outages and left approximately 2.7 million customers (equivalent to five million or more individuals) without power, some for multiple hours extending into the next day. The total load loss for the event was in excess of 30,000 MWh. The event started with a three-phase fault which led to the loss of Arizona Public Service Company's (APS) Hassayampa-N. Gila 500 kV transmission line (H-NG). This transmission line is a segment of the Southwest Power Link (SWPL), a major transmission corridor transporting power in an east-west direction, from generators in Arizona, through Imperial Irrigation District's (IID) service territory, into Southern California.

10. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the electric system in the Pacific Southwest and Southern California, increasing flows through lower voltage systems parallel to the SWPL as power continued to flow on a hot day during hours of peak demand.

11. These redistributed flows traveled through IID's and Western Area Power Administration-Desert Southwest Region's (Western-DSW) facilities, onto WECC Path 44, an aggregation of five 230 kV transmission lines that deliver power in a north-south direction from Southern California Edison Company's (SCE) territory in Los Angeles to San Diego Gas & Electric (SDG&E). The increased power flows parallel to the SWPL, together with lower than peak generation levels in California and Mexico, led to significant voltage deviations and transmission equipment overloads. The flow redistributions, voltage deviations, and resulting overloads had a cascading effect, as transmission and generation equipment tripped offline in a relatively short time period. Just seconds before the blackout, Path 44 carried all flows into San Diego as well as parts of Arizona and Mexico. This excessive loading on Path 44 initiated an intertie separation scheme owned and operated by SCE at the San Onofre switchyard. The California Independent System Operator (CAISO) is responsible for many of the TOP functions for SCE under a Coordinated Functional Registration. Initiation of the intertie separation scheme at the San Onofre switchyard separated SDG&E from Path 44, contributed to tripping the San Onofre Nuclear Generating Station nuclear units offline, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's Baja California Control Area in Mexico.

12. WECC RC was the highest reliability authority at the time of the event and maintained a wide-area view of the entire Interconnection. WECC RC was staffed with

[3] 16 U.S.C. § 824o (2012).

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two operators (one real-time operator and one study desk operator) in each of its two regional offices at the time of the event.

13. Promptly after WECC RC's alarms reflected the loss of H-NG, WECC RC operators contacted APS, the operator of H-NG, to discuss the status of H-NG. APS operators informed WECC RC operators that APS could restore H-NG within minutes. WECC RC operators relied on the statement by APS operators that APS could restore H-NG within minutes, and issued no reliability directives in connection with the event, which lasted only 11 minutes (not including restoration). WECC RC and APS operators did not discuss the existing large phase angle difference between Hassayampa and N. Gila that needed to be addressed before H-NG could be returned to service.

14. Prior to the event, WECC RC conducted a next-day study for the entire Western Interconnection, using a model that included, among other equipment, IID's 230 /92 kV transformers. However, the study did not include the effects of the S-Line remedial action scheme (RAS) and separation scheme at the San Onofre switchyard. At the time of the event, WECC excluded from its interpretation of the definition of special protection systems/remedial action schemes (SPSs/RASs) certain types of protection systems, including the S-Line RAS and the separation scheme at the San Onofre switchyard. As a result, WECC RC and the TOPs did not study those systems and schemes. Additionally, WECC RC only reviewed the TOPs' next-day studies when it identified an issue in its own next-day study. WECC RC did not review IID's next-day study for September 8.

15. WECC RC was responsible for monitoring all critical facilities in the Western Interconnection, which may include facilities below 100 kV, as necessary to ensure that at any time, regardless of unplanned events, it was able to determine system operating limits (SOLs) and interconnection reliability operating limits (IROLs), and to know the status of all critical facilities whose failure could result in an SOL or IROL exceedance. On September 8, a WECC RC operator was alerted by an alarm in real time to the fact that IID's 230/92 kV Coachella Valley transformers had tripped (WECC RC had real-time visibility of the transformers even though they were not classified as BES facilities at the time), but was unaware that those transformers tripping could result in a previously unidentified IROL. The September 8 event also exposed SOLs that were previously unrecognized by WECC RC, by revealing that operating WECC Path 44 to an SOL of 2,200 MW, and H-NG (a portion of WECC Path 49), to a limit of 1800 MW, would expose the WECC RC area to cascading outages.

16. Prior to the event, the Operating Practices Subcommittee of WECC's Operating Committee stated an operating philosophy that no IROLs existed under normal operating conditions. As a result, WECC RC did not recognize any IROLs in the Western Interconnection. Following the exposure of the Coachella Valley 230/92 transformers IROL by the September 8 event, WECC RC has since recognized the existence of several IROLs in the Western Interconnection, and Peak continues to analyze the Interconnection

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for additional IROLs. At the time of the event WECC RC also delegated to TOPs the responsibility for identifying criteria that determine when violating an SOL qualifies as an IROL.

17. WECC RC was aware of post-contingency overloads within Western-DSW and IID, but did not alert Western-DSW and IID to these potential transmission problems.

II. Investigation

18. On September 9, 2011, the Commission and NERC announced a joint inquiry to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. The inquiry team, comprised of Commission and NERC staff, used on-site visits and interviews, detailed computer modeling, event simulations, and system analyses to make its findings and recommendations for preventing similar events in the future. The inquiry determined that entities responsible for planning and operating the BPS were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency. On May 1, 2012, the inquiry team published a report entitled *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (the Report), which is hereby incorporated by reference.[4] The Report discusses a detailed sequence of events, simulations, and findings related to the causes of the cascading outages. The Report also makes twenty-seven recommendations related to next-day planning, seasonal planning, near- and long-term planning, situational awareness, consideration of BES equipment, SOLs and IROLs, and protection systems.

19. Following publication of the Report, Enforcement, OER, and NERC staff reviewed the data gathered during the inquiry for compliance implications. At the direction of the Commission, Enforcement initiated non-public investigations of several entities, including WECC, under Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014), which were conducted jointly with NERC.

20. Enforcement and NERC determined that WECC violated the Facilities Design, Connection and Maintenance (FAC) and Interconnection Reliability Operations and Coordination (IRO) groups of Reliability Standards. The IRO Reliability Standards "detail the responsibilities and authorities of [an RC]," and "establish requirements for data, tools and wide-area view, all of which are intended to facilitate [an RC's] ability to perform its responsibilities and ensure the reliable operation of the interconnected grid."[5] The FAC standards at issue aim to ensure that SOLs are determined based on an established methodology.

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[4] *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

[5] Order No. 693 at P 888.

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21. Enforcement and NERC determined that WECC RC violated nine Requirements of five Reliability Standards: FAC-011-2 R3; FAC-014-2 R1; IRO-003-2 R1 and R2; IRO-004-1 R1; and IRO-005-2 R5, R9, R12, and R15—stemming from its role in the September 8 event.

22. Enforcement and NERC staff determined that WECC RC violated IRO-003-2 R1 and R2 because WECC RC was unaware that IROLs such as the Coachella Valley 230-92 kV transformers existed in its control area, and thus did not determine or prevent IROL violations on September 8, 2011.

23. Enforcement and NERC staff determined that WECC RC violated IRO-004-1 R1 and IRO-005-2 R5, R9, and R15 because it did not identify the cause of potential and actual SOL and IROL violations on Paths 44 and 49, mitigate the violations, and alert impacted TOPs and BAs in its area.

24. Enforcement and NERC staff determined that WECC RC violated IRO-005-2 R12 because it was not aware of the impact of the S-line RAS and separation scheme at the San Onofre switchyard.

25. Enforcement and NERC staff determined that WECC RC violated FAC-011-2 R3 and FAC-014-2 R1 as a result of inadequacies in its SOL methodology that resulted in the establishment of unreliable SOLs for Paths 44 and 49 and the failure to identify IROLs.

III. Stipulation and Consent Agreement

26. Enforcement, NERC, WECC and Peak resolved this matter by means of the attached Agreement. WECC stipulates to the facts recited in the Agreement and agrees to pay a civil penalty of $16,000,000, of which $3,000,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $13,000,000 will be invested by WECC and Peak in Reliability Enhancements that go above and beyond the requirements of the Reliability Standards, as described in the Agreement. WECC and Peak also agree to mitigation and reliability activities, and to submit to compliance monitoring, as specified in the Agreement. WECC neither admits nor denies that its actions constituted violations of the Reliability Standards.

27. In determining the appropriate sanction, Enforcement considered that WECC has made significant efforts to date to address reliability concerns identified in the inquiry and investigation and also by WECC on its own initiative. WECC also cooperated with Enforcement and NERC during the investigation.

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IV. Determination of the Appropriate Sanctions

28. The civil penalty amount is consistent with the Penalty Guidelines.[6] Enforcement considered that the event caused a loss of 10,000 or more MWh of firm load, and WECC was allocated a share of the base penalty due to its role as the RC. WECC RC also had a prior history of violations of the Reliability Standards, including two violations based on conduct substantially similar to that at issue in this event.[7] The civil penalty amount reflects credit for WECC's cooperation during the course of the investigation, as well as credits for avoiding a trial-type hearing and having an effective compliance program.

29. The Commission concludes that the penalties and other sanctions set forth in the Agreement are a fair and equitable resolution of this matter and are in the public interest. The Commission also concludes that the reliability enhancement, mitigation and reliability activities set forth in the Agreement will enhance the reliability of the BPS and are therefore also fair and in the public interest.

The Commission orders:

The attached Stipulation and Consent Agreement is hereby approved without modification.

By the Commission. Chairman Bay is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

[6] *Enforcement of Statutes, Orders, Rules and Regulations,* 132 FERC ¶ 61,216 (2010).

[7] *Western Electricity Coordinating Council,* 136 FERC ¶ 61,020 (2011) (including lack of awareness of SPS within its RC area under IRO-005-1 R12); Notice of Penalty, Docket No. NP11-259-000, September 9, 2011 (including failure to coordinate with TOPs to mitigate SOL exceedance under IRO-005-1 R9).

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Western Electricity Coordinating Council) Docket No. IN14-11-000

STIPULATION AND CONSENT AGREEMENT

I. INTRODUCTION

1. Staff of the Office of Enforcement (Enforcement) of the Federal Energy Regulatory Commission (Commission), the North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Peak Reliability (Peak) enter into this Stipulation and Consent Agreement (Agreement) to resolve a non-public investigation conducted by Enforcement and NERC pursuant to Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014). The investigation examined possible violations of NERC Reliability Standards by WECC as the Reliability Coordinator (RC) for the Western Interconnection (WECC RC)) related to a system event in the Pacific Southwest on September 8, 2011 (September 8 event or event). WECC neither admits nor denies that WECC RC violated the Reliability Standards described in the Agreement, but agrees to pay a total civil penalty of $16,000,000, of which $3,000,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $13,000,000 will be invested in reliability enhancement measures identified below that go above and beyond the Agreement's mitigation and reliability activities or what the Reliability Standards require (Reliability Enhancements). Peak did not exist as a separate entity at the time of the September 8 event, but is a party to the Agreement as the successor to WECC as the RC for the Western Interconnection. WECC and Peak also commit to certain measures, subject to compliance monitoring, as detailed in the Agreement.

II. STIPULATED FACTS

2. Enforcement, NERC, and WECC and Peak hereby stipulate and agree to the following facts.

A. WECC

3. WECC is a non-profit, public service corporation and is not a load-serving entity. WECC is funded by assessments to load-serving entities, among others. At the time of the event, WECC acted as both the Regional Entity (WECC RE) and the RC for the Western Interconnection. These functions were organized separately, but reported to the same WECC executive management. WECC RC was a NERC Registered Entity, and was the highest level of authority responsible for the reliable operation of the Bulk Electric System (BES) in the Western Interconnection.

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4. The RC of the Western Interconnection (formerly WECC RC, now Peak) is responsible for overseeing operation of the Western Interconnection in real time, receiving data from entities throughout the entire Interconnection, and providing high-level situational awareness for the entire system. The RC has the authority to prevent or mitigate emergency operating conditions in the next-day and real-time timeframes. The RC may issue directives to other functional entities to ensure reliable operations. The RC performs reliability analyses including next-day planning and real-time contingency analysis (RTCA) for the Western Interconnection. The RC may also assist transmission operators (TOPs) in mitigating equipment overloads and coordinating restoration plans, contingency plans, and reliability-related services.

5. As the RE, WECC or its delegate, among other things, monitors compliance of Registered Entities (including, formerly, WECC RC and currently, Peak) with the Reliability Standards, under delegated authority from NERC.

6. After the event, WECC sought approval from the Commission to establish a new entity to perform the RC and interchange authority (IA) functions in the Western Interconnection. The bifurcation of WECC into two separate entities, WECC and Peak, received final approval from the Commission on February 12, 2014.[1] With the Commission's approval, WECC sub-delegated the RC and IA functions in the Western Interconnection to Peak. WECC has retained its RE responsibilities.

B. Event Description

7. During an 11-minute period on the afternoon of September 8, 2011, a system disturbance occurred in the Pacific Southwest, resulting in cascading outages and leaving approximately 2.7 million customers without power, some for multiple hours extending into the next day. The total load loss for the event was in excess of 30,000 MWh. The event started with a three-phase fault which led to the loss of Arizona Public Service's (APS) Hassayampa-N. Gila 500 kV transmission line (H-NG). This transmission line is a segment of the Southwest Power Link (SWPL), a major transmission corridor transporting power in an east-west direction, from generators in Arizona, through the service territory of Imperial Irrigation District (IID), into Southern California.

8. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the electric system in the Pacific Southwest and Southern California, increasing flows through lower voltage systems parallel to the SWPL as power continued to flow on a hot day during hours of peak demand.

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[1] *See North American Electric Reliability Corp.*, 146 FERC ¶ 61,092 (2014*), reh'g denied*, 147 FERC ¶ 61,064 (2014) (accepting compliance filings submitted by NERC and WECC and eliminating all final obstacles to bifurcation), appeal docketed *sub nom Edison Electric Institute v. FERC*, No. 14-1071 (D.C. Cir. May 9, 2014).

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9. These redistributed flows traveled through IID's and Western Area Power Administration – Desert Southwest Region's facilities (Western-DSW), onto WECC Path 44, an aggregation of five 230 kV transmission lines that deliver power in a north-south direction from Southern California Edison Company's (SCE) territory in Los Angeles to San Diego Gas and Electric (SDG&E). The increased power flows parallel to the SWPL, together with lower than peak generation levels in California and Mexico, led to significant voltage deviations and transmission equipment overloads. The flow redistributions, voltage deviations, and resulting overloads had a cascading effect, as transmission and generation equipment tripped offline in a relatively short time period. Just seconds before the blackout, Path 44 carried all flows into San Diego as well as parts of Arizona and Mexico. This excessive loading initiated an intertie separation scheme owned and operated by SCE at the San Onofre switchyard. The California ISO (CAISO) is responsible for many of the TOP functions for SCE under a Coordinated Functional Registration. Initiation of the intertie separation scheme at the San Onofre switchyard separated SDG&E from Path 44, contributed to tripping the San Onofre Nuclear Generation Station nuclear units offline, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's Baja California Control area.

10. WECC RC was the highest reliability authority at the time of the event and maintained a wide-area view of the entire Interconnection. WECC RC was staffed with two operators (one real-time operator and one study desk operator) in each of its two regional offices at the time of the event.

11. Promptly after WECC RC's alarms reflected the loss of H-NG, WECC RC operators contacted APS, the operator of H-NG, to discuss the status of H-NG. APS operators informed WECC RC operators that APS could restore H-NG within minutes. WECC RC operators relied on the statement by APS operators that APS could restore H-NG within minutes, and issued no reliability directives in connection with the event, which lasted only 11 minutes (not including restoration). WECC RC and APS operators did not discuss the existing large phase angle difference between Hassayampa and N. Gila that needed to be addressed before H-NG could be returned to service.

12. Prior to the event, WECC RC conducted a next-day study for the entire Western Interconnection, using a model that included, among other equipment, IID's 230 /92 kV transformers. However, the study did not include the effects of the S-Line remedial action scheme (RAS) and separation scheme at the San Onofre switchyard. At the time of the event, WECC excluded from its interpretation of the definition of special protection systems/remedial action schemes (SPSs/RASs) certain types of protection systems, including the S-Line RAS and the separation scheme at the San Onofre switchyard, among others. As a result, WECC RC and the TOPs did not study those systems and schemes. Additionally, WECC RC only reviewed the TOPs' next-day studies when it identified an issue in its own next-day study. WECC RC did not review IID's next-day study for September 8.

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13. WECC RC was responsible for monitoring all critical facilities in the Western Interconnection, which may include facilities below 100 kV, as necessary to ensure that at any time, regardless of unplanned events, it was able to determine system operating limits (SOLs) and interconnection reliability operating limits (IROLs), and to know the status of all critical facilities whose failure could result in an SOL or IROL exceedance. On September 8, a WECC RC operator was alerted by an alarm in real time to the fact that IID's 230/92 kV Coachella Valley transformers had tripped (WECC RC had real-time visibility of the transformers even though they were not classified as BES facilities at the time), but was unaware that those transformers tripping could result in a previously unidentified IROL. The September 8 event also exposed SOLs that were previously unrecognized by WECC RC, by revealing that operating WECC Path 44 to an SOL of 2,200 MW, and H-NG (a portion of WECC Path 49) to a limit of 1800 MW, would expose the WECC RC area to cascading outages.

14. Prior to the event, the Operating Practices Subcommittee of WECC's Operating Committee stated an operating philosophy that no IROLs existed under normal operating conditions. As a result, WECC RC did not recognize any IROLs in the Western Interconnection. Following the exposure of the Coachella Valley 230-92 transformers IROL by the September 8 event, WECC RC has since recognized the existence of several IROLs in the Western Interconnection, and Peak continues to analyze the Interconnection for additional IROLs. At the time of the event WECC RC also delegated to TOPs the responsibility for identifying criteria that determine when violating an SOL qualifies as an IROL.

15. WECC RC was aware of post-contingency overloads within Western-DSW and IID, but did not alert Western-DSW and IID to these potential transmission problems.

III. INQUIRY AND INVESTIGATION

16. On September 9, 2011, the Commission and NERC announced a joint inquiry to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. The inquiry team, comprised of Commission and NERC staff, used on-site visits and interviews, detailed computer modeling, event simulations, and system analyses to make its findings and recommendations for preventing similar events in the future. The inquiry determined that entities responsible for planning and operating the bulk-power system (BPS) were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency. On May 1, 2012, the inquiry team published a report entitled *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (the Report), which is hereby incorporated by reference.[2] The Report discusses a detailed sequence of events, simulations, and findings

[2] *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

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related to the causes of the cascading outages. The Report also makes twenty-seven recommendations related to next-day planning, seasonal planning, near- and long-term planning, situational awareness, consideration of BES equipment, SOLs and IROLs, and protection systems.

17. Following publication of the Report, Enforcement and NERC reviewed the data gathered during the inquiry for compliance implications. As a result of that review, Enforcement and NERC initiated non-public investigations of several entities, including WECC, under Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014).

18. Enforcement and NERC determined that WECC violated nine Requirements of five Reliability Standards, and found these violations undermined the reliability of the BPS and contributed to the September 8 event. Enforcement and NERC recognized, however, that after the event, and during the inquiry and investigation, WECC voluntarily began making improvements in its planning and operations, and implementing recommendations from the Report, that addressed many of the findings arising from the Report. WECC established an online Dashboard to track its progress. In addition, WECC cooperated with Enforcement and NERC during the investigation.

19. As part of the investigation, Enforcement and NERC reviewed WECC's compliance program (as it existed at the time of the event) and found that WECC satisfied the criteria for an effective compliance program under the Commission's Penalty Guidelines.[3] Enforcement and NERC considered the elements of WECC's compliance program set forth in this paragraph. At the time of the September 8 event, WECC RC had a formal compliance program. WECC RC had a designated Compliance Manager, who had direct access to WECC senior executives and, as necessary, the WECC board. All WECC team members were expected to collaborate in the implementation of practices and policies meant to ensure compliance with all rules and regulations. All WECC team members underwent mandatory training on the Reliability Standards relevant to their positions, as well as training on the benefits of compliance and the risks of non-compliance. Peak has built upon WECC's compliance program. Under Peak's current program, the Compliance Director reports directly to the President and Chief Executive Officer, with access to the Chair of the Board of Directors as needed. The Compliance Director is directly supported by an Operations Compliance Specialist and CIP Compliance Specialist, with all Peak team members required to collaborate to develop and implement policies, procedures, work practices and technologies to ensure compliance with the Reliability Standards. Peak has a "Compliance Open Door Policy" that encourages all team members to bring compliance issues to the attention of management, whether through direct report to the Compliance Director, or anonymous

[3] *Enforcement of Statutes, Orders, Rules and Regulations,* 132 FERC ¶ 61,216, § 1B2.1 (2010).

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reporting to a third-party compliance reporting service provider. All Peak team members undergo mandatory compliance training relevant to their positions, and new hires are trained on the Reliability Standards, benefits of compliance, risks of non-compliance, the Compliance Open Door Policy, and Peak's rewards for compliance and disciplinary measures for non-compliance.

IV. ENFORCEMENT AND NERC FINDINGS OF VIOLATIONS

20. Enforcement and NERC staff determined that WECC RC violated the following Requirements of the Reliability Standards: FAC-011-2 R3; FAC-014-2 R1; IRO-003-2 R1 and R2; IRO-004-1 R1; and IRO-005-2 R5, R9, R12, and R15.[4] Enforcement and NERC staff determined that WECC RC violated IRO-003-2 R1 and R2 because WECC RC was unaware that IROLs existed in its control area and were violated on September 8, 2011. Enforcement and NERC staff determined that WECC RC violated IRO-004-1 R1 and IRO-005-2 R5, R9, and R15 because it did not identify the cause of potential and actual SOL and IROL violations, mitigate the violations, and alert impacted TOPs and Balancing Authorities (BAs) in its area. Enforcement and NERC staff determined that WECC RC violated IRO-005-2 R12 because it was not aware of the impact of the S-line RAS and separation scheme at the San Onofre switchyard. Lastly, Enforcement and NERC staff determined that WECC RC violated FAC-11-2 R3 and FAC-014-2 R1 for inadequacies in its SOL methodology that resulted in the establishment of unreliable SOLs and the failure to identify IROLs.

V. REMEDIES AND SANCTIONS

21. WECC stipulates to the facts as described in Section II of this Agreement, but neither admits nor denies Enforcement's and NERC's findings that WECC RC violated the Reliability Standards specified in Section IV. For purposes of settling any and all disputes within the jurisdiction of the Commission arising from any and all reliability matters related to the September 8 event, or Enforcement's and NERC's investigation, WECC agrees to the remedies and sanctions set forth in the following paragraphs assigned to WECC, including the entire cash payment to Treasury and NERC, and Peak agrees to the remedies assigned to Peak. Pursuant to the Revised Reliability Coordinator and Interchange Authority Agreement between the Western Electricity Coordinating Council and Peak Reliability (RC Agreement), Peak is responsible for reporting obligations and enforcement conditions relating to its role as the RC, and WECC is responsible for reporting obligations and enforcement conditions relating to its role as the RE.

[4] As noted in paragraphs 1 and 21, WECC neither admits nor denies the findings by Enforcement and NERC regarding violations of the Reliability Standards, and use of the term mitigation is not meant to imply otherwise.

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A. Civil Penalty

22. WECC shall pay a total civil penalty of $16,000,000, of which $3,000,000 shall be paid, divided in equal amounts, to the United States Treasury and NERC. $1,000,000, divided equally between the United States Treasury and NERC, shall be due within ten days of the Effective Date of the Agreement. $1,000,000, divided equally between the United States Treasury and NERC, shall be due within one year from the Effective Date and $1,000,000, divided equally between the United States Treasury and NERC, shall be due within two years of the Effective Date. Enforcement and NERC agree to give WECC a partial civil penalty offset for the remaining $13,000,000 in exchange for WECC and Peak implementing the Reliability Enhancements as set forth in section V.B. The value of the Reliability Enhancements is expected to substantially exceed the amount of the offset.

B. Reliability Enhancements

23. In exchange for the $13,000,000 offset, WECC and Peak have completed or shall complete the following Reliability Enhancements:

a. WECC RC partially increased, and Peak has continued to and shall increase, staffing of the RC function from the staffing in effect on September 8, 2011, by 61 full-time equivalent positions, including 18 RC operators. Peak shall maintain the additional 18 RC operator positions at least through December 31, 2016; and

b. WECC completed bifurcation of the RE function of WECC from the RC function, with the RC function sub-delegated to Peak on February 14, 2014.

24. WECC and Peak will provide Enforcement and NERC with satisfactory evidence that investments to date in the Reliability Enhancements have substantially exceeded $13,000,000.

C. Completed and Required Mitigation and Reliability Activities

25. WECC and Peak, respectively, commit to the designated actions in this Section V.C. As indicated below, WECC and Peak affirm that they have already completed most of the mitigation and reliability activities, and shall complete all remaining mitigation and reliability activities no later than one year after the Effective Date of the Agreement, unless otherwise stated in Section V.C. WECC and Peak shall continue operating consistent with the completed and required mitigation and reliability activities, until they implement improved practices and procedures in accordance with the Reliability Standards in existence now or in the future. Until WECC and Peak have completed all mitigation and reliability activities and Reliability Enhancements, any material alterations in the mitigation and reliability activities set forth in Section V.C. shall be approved by

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Enforcement and NERC staff, such approval not to be unreasonably withheld. WECC and Peak will individually or jointly report on the status of all mitigation and reliability activities described in this Section V.C. and submit evidence of progress and/or completion in their compliance monitoring reports to be submitted to Enforcement and NERC pursuant to Section V.D of this Agreement. WECC and Peak agree to work cooperatively to provide Enforcement and NERC staff with information necessary to confirm that all mitigation and reliability activities have been completed.

i. Seasonal, Next-Day and Current-Day Planning

26. Peak now shares its next-day study, as well as study inputs such as outages and interchange, electronically on a daily basis with all WECC entities that have executed the Universal Data Sharing Agreement (UDSA). WECC RC and Peak created additional formats for TOPs to review the RC studies, including Power System Simulator for Engineering (PSS/E) and Positive Sequence Load Flow (PSLF). After the September 8 event, WECC and Peak obtained executed UDSAs from all Western Interconnection BAs, TOPs and Transmission Owners (TOs). Peak and the TOPs are engaged in negotiations to renew the UDSA. The Peak Board of Directors has established a bridge policy to ensure that access to data sharing is maintained during the negotiations.

27. Peak has improved the forecasting of interchange between TOPs by working with BAs to identify the reasons for forecasting errors, and to improve the unit commitment data provided to the RC. Peak worked with the BAs to address unit commitment data issues that were identified by a task force that reviewed input data issues related to the RC's next-day studies. All data issues related to unit commitment and interchange forecasting identified by the task force have been remedied.

28. By June 30, 2015, WECC will issue a guideline outlining best practices for next-day studies, which will be posted on the WECC website. WECC will monitor the effectiveness of this guideline through a next-day study working group and the annual Operational Practices Survey, or other appropriate means.

29. In February 2014, WECC issued its "Pre/Post-Contingency Guideline," which guides TOPs to take pre-contingency mitigation measures when potential post-contingency conditions could exceed the TOPs' highest emergency rating for a facility. The Guideline also reminds TOPs to consider the time necessary to take mitigation actions, and to consider the effect of relays that automatically isolate facilities without providing time for mitigating measures. WECC has posted this guideline on the WECC website, and will monitor its effectiveness through the annual Operational Practices Survey, or other appropriate means.

30. Peak shall coordinate the seasonal planning process for its RC area. Seasonal planning by TOPs in the Western Interconnection begins with the operational base cases prepared by WECC. WECC shall continue to prepare operational base cases. WECC

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and Peak shall cooperate, to the extent applicable, to gather information from TOPs to update the operational base cases. WECC RC and Peak have worked with the sub regional study groups to facilitate a consistent method for seasonal planning, including consistency in system conditions to be evaluated and consistency in process. WECC RC also worked with the sub regional study groups to improve coordination between seasonal study planners and operators. Peak shall require, per its SOL methodology and seasonal coordination process, that the seasonal planning for the Western Interconnection includes all critical internal and external conditions and contingencies, including generation and transmission outages, transfers, and demand patterns, including non-peak demand patterns. Critical internal and external facilities may be sub-100 kV, if they impact the BES. To the extent required by changes to the Reliability Standards related to planning, Peak will consult with FERC and NERC on how to satisfy the measures contained in this paragraph.

31. WECC has developed a procedure to perform N-1 contingency analysis on operational base cases for the Western Interconnection. WECC will implement this procedure by June 30, 2015, and will provide the results of its analysis to the area coordinators within 30 days after WECC completes its analysis.

j. Near- And Long-Term Planning

32. WECC established the Planning Coordinator Function Task Force to identify the current Planning Coordinator (PC) issues in the Western Interconnection, evaluate gaps in PC coverage in the Western Interconnection and to develop a methodology, procedures and implementation plan for addressing the PC issues in the Western Interconnection. In addition, using the results of a survey issued to registered PCs, WECC has identified those facilities within each current PC area, as well as facilities in areas for which no PC has been identified. WECC shall provide the Planning Coordinator Function Task Force's report (and any other deliverables) to Enforcement and NERC within 7 days of completion by the Task Force. After receipt of the report and deliverables, WECC, Peak, and FERC and NERC staff shall confer and cooperate in order to reach an agreement on a solution for the PC issues in the Western Interconnection, especially the gaps in PC coverage and seams issues.[5]

33. In July, 2014, WECC issued a BES Inclusion Guideline, which recognized that non-BES, or sub-100 kV, facilities may be important to the reliability of the Interconnection. The Guideline helps registered entities identify such facilities, and encourages, but does not require, registered entities to consider facilities for inclusion in

[5] Seams issues refers to the fact that transmission lines, interchange and loop flow patterns, among other characteristics of the BES, cross the boundaries between entities or sub regional groups, and thus may not be consistently analyzed by any individual entity or sub regional group.

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the BES through the NERC exception procedures. Among other situations that might qualify a non-BES facility for inclusion through the NERC exception procedures are facilities identified as a significant contributing factor in an event analysis report, or where the facility's single-contingency outage changes the flow on any BES element by more than 10 percent. WECC will monitor the effectiveness of the guideline through its annual Operational Practices Survey, or other appropriate means.

k. Protection Systems

34. Peak has included 239 additional RASs, and greater specificity about the existing RASs, in the models used for Peak's RTCA. Peak has also added 212 additional RASs to its Supervisory Control and Data Acquisition (SCADA) displays, and 4701 additional RAS Inter-Control Center Communication Protocol points, since the event.

35. By March 31, 2016, WECC will have developed the capability for entities to model RASs so that they can be added to its powerflow base cases. By June 30, 2016, WECC will update the Data Preparation Manual to include the requirement for data submitters to include RAS models in their submittal to WECC. WECC will produce the first powerflow base case to include RAS models by July 2016. By June 30, 2017, all WECC base cases shall include all (1) RASs, and (2) overcurrent protection relays with inter-TOP impact, known to WECC to exist in the Western Interconnection as of the Effective Date. In the interim, WECC collected and posted some data on RASs and relays with inter-TOP impact so that entities can model those impacts until those RASs and relays are modeled in the WECC base cases. Any RASs installed in the Western Interconnection after June 30, 2016 and known to WECC to exist shall be modeled in the base cases as soon as practicable in coordination with WECC's established base case production schedule.

36. WECC developed and adopted the Regional Criterion entitled "Remedial Action Scheme Review and Assessment Plan, PRC-(012 through 14)-WECC-CRT-2," which became effective January 1, 2014 (an earlier version became effective in October 2011). This criterion requires TOs, Generator Owners and Distribution Providers to submit data on RASs initially and before putting any changes or new RASs in service, to review the information in WECC's Remedial Action Scheme Database annually for accuracy, and to assess their RASs for operation, coordination, and effectiveness at least once every five years, among other requirements. This criterion also requires WECC's Remedial Action Scheme Reliability Subcommittee (RASRS) to review each RAS submitted to the RASRS for compliance with designated Reliability Standards, including Standards within the Transmission Planning and Protection Systems groups. As a result of this criterion, WECC has gathered data on multiple existing and new schemes. In addition, the RASRS chair issued a data request to all Western Interconnection TOPs requesting them to provide information on any tie line schemes or safety nets within their systems. That effort identified 25 additional RASs from seven entities that were incorporated into the Remedial Action Scheme Database. The information collected through the criterion will

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facilitate the WECC modeling process and assist in the identification of interaction among RASs.

37. WECC prepared a white paper on "The Recognition of Power Plant Control, Protection and Operation in Transmission Simulation Studies," which was posted on the WECC website.

38. In November, 2012, WECC issued its Guideline for Protection System Loadability. The guideline encourages TOPs to set load-responsive relays that are operated in parallel with the BES, but not subject to Reliability Standard PRC-023, to use one of the setting criteria from PRC-023. The Guideline also addresses phase angle differences used when reclosing a breaker, encouraging the TOPs to provide visibility of the phase angle difference by means that could include planning studies, State Estimator, Real-time Contingency Analysis (RTCA), Phasor Measurement Units, or synch check relays. WECC posted this guideline on the WECC website, and will monitor its effectiveness through the annual Operational Practices Survey, or other appropriate means.

l. Angular Separation

39. Since September 2011, WECC RC and Peak have improved the ability of the RC to estimate phase angle differences. Peak can monitor estimated or expected (post-contingency) phase angles using Real-time State Estimation and RTCA. A procedure exists, called *Monitoring Heavy E-W Flows on SWPL*, which describes action to be taken by the RC operator when exceeding phase angle line reclosure limits (synch check relay thresholds) on the SWPL. In addition to its focused monitoring of the phase angles on the SWPL, Peak also monitors fifteen other node-pairs in the Western Interconnection for, among other things, excessive phase angles. If a relevant line is open and results in the exceedance of a node-pair phase angle limit, Peak RC System Operators will see that exceedance in Peak's Energy Management System (EMS) applications. An actual exceedance of a node-pair phase angle limit is detected and reported in Peak's Real-time State Estimation. A post-contingency exceedance of a node-pair phase angle limit is detected and reported in Peak's RTCA and study contingency analysis applications. The node-pair phase angle limits currently implemented in Peak's EMS inform the RC System Operators that the relevant line cannot be reclosed because of the excessively high phase angle.

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m. System Operating Limits and Interconnection Reliability Operating Limits

40. After September 8, 2011, WECC began using a new SOL methodology, and further refined that methodology with its "Phase II SOL Methodology," Revision 7.0 of the SOL Methodology for the Operations Horizon, which became effective in March 2014. Among other things, the SOL Methodology currently in use by TOPs in the Western Interconnection and Peak instructs entities to assess projected system conditions as real time approaches to establish SOLs, and includes criteria for identifying the subset of SOLs that qualify as IROLs in real time, as well as a clearer definition of what is included in an SOL. The SOL methodology requires TOPs and the RC to operate in real time to the most restrictive of Facility Ratings, voltage limits, voltage stability limits, transient stability limits or WECC Path Ratings. Prior to the event, some TOPs operated only to Path Ratings or seasonally-determined SOLs. The SOL methodology also requires TOPs to use models for establishing SOLs and IROLs that include the entire WECC RC area, to include critical modeling details from other RC areas that would impact the facilities being studied, to model parallel sub-100 kV facilities (e.g., the Coachella Valley transformers), to include RASs/SPSs in their models where feasible, and to consider the impact of SPS/RAS actions when establishing SOLs and IROLs. Current IROLs recognized by Peak are posted online in the secure area of peakrc.org.

41. Peak shall make the following modifications to the SOL Methodology for the Operations Horizon:

a. Peak shall not exclude all load loss due to RAS/SPS actions for the purpose of determining whether an IROL exists, because to do so would have allowed the Coachella Valley transformers to elude recognition as an IROL; and

b. Peak shall justify the reason for the 1,000 MW cut-off for SOLs to be IROLs or establish a cut-off with technical justification.

n. Situational Awareness

42. Peak runs its RTCA every five minutes and Peak's RTCA results and certain State Estimator Savecases are immediately available to all TOPs and BAs in real time in the secure area of peakrc.org.

43. WECC RC began flagging and alarming the two Coachella Valley transformers in its RTCA shortly after the September 8, 2011 event. Peak shall continue to flag and alarm the Coachella Valley transformers.

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44. WECC RC and Peak have allowed TOPs to view the Coordinated Outage System once the TOPs executed the UDSA. All current TOPs have now executed the UDSA.[6]

45. WECC and Peak have increased real-time data sharing among TOPs by developing the WECC Operations Network guideline. WECC has posted this guideline on the WECC website, and will monitor its effectiveness through the annual Operational Practices Survey, or other appropriate means.

46. Peak has modified its data request to require each TOP to provide telephone notification to Peak when the TOP loses real-time data or RTCA. Peak will modify the Data Request to require notification either by telephone or by WECCNET, if possible.

47. WECC has issued a Real-Time Tools Guideline. Among other recommendations for best practices, it guides TOPs on the scope of their network model (to allow identification of external contingencies, for example), on how often to update their state estimator (every 10 minutes) and RTCA (at least every 30 minutes). WECC has posted this guideline on the WECC website, and will monitor its effectiveness through the annual Operational Practices Survey, or other appropriate means.

o. Emergency Operations

48. WECC has issued an Emergency Operations Procedure, which, among other things, defines the RC operator's role during emergency operations and in evaluating emergency conditions, including major system disturbances. The Procedure also provides specific guidance to RC operators on issuing "clear, concise and definitive" Reliability Coordinator Directives.

p. Modeling

49. WECC is developing the Base Case Coordination System (BCCS), to validate data automatically, build power flow base cases, and store dynamic data in a centralized, Web-accessible database. WECC is in the process of implementing the BCCS, and expects to fully implement the BCCS by June 30, 2016. WECC has offered training in the use of the BCCS to all TOPs in the Western Interconnection. If, despite its good faith and diligent efforts, WECC is unable to fully implement the BCCS due to irreconcilable technical issues or vendor performance, WECC, FERC and NERC staff shall confer and cooperate in order to reasonably address through other means any identified issues regarding validation of base case data or revision of power flow base cases.

[6] See paragraph 26 regarding the renegotiation of the UDSA, and interim measures to preserve data sharing.

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50. WECC and its Transmission Planners (TPs) have benchmarked their dynamic models against actual data from the September 8, 2011 event, as recommended by the Report. WECC worked with the TPs to identify modeling deficiencies and track improvements, and all modeling deficiencies identified as a result of the model validation process have been corrected.

51. WECC continues to reconcile its planning base cases to the Peak West-wide System Model used for operations, as recommended by the Report, and WECC and Peak continue to make any necessary changes in the two models.

52. WECC has added a generator tripping model to its base cases to provide an indication of when generators may trip during events.

53. WECC and Peak have conducted a two-phase study to identify facilities with at least one terminal below 100 kV that have an impact on the BES. In the first phase, WECC and Peak worked with TOPs to obtain a list of sub-100 kV facilities that the TOPs believed should be monitored due to potential loop flow, and performed a study using the Peak West-wide System Model. In the second phase, a study was conducted using WECC's planning model. WECC and Peak identified additional sub-100 kV facilities to be added to the Peak West-wide System Model and Peak's EMS model, and Peak is monitoring additional facilities identified by TOPs. Peak has alarmed all facilities identified through these studies in its EMS.

54. WECC will benchmark a base case, including dynamic models, on an annual basis, against actual system performance during the single most severe reportable disturbance that occurred on the Western Interconnection during the previous year. On a prospective basis, WECC will work with PCs and TPs to modify any discrepancies found between the base case (including dynamic models) and actual system performance.

q. **Voltage and Reactive Reserves**

55. WECC RC, and later Peak, implemented a voltage stability tool, the Region of Stability Excellence, or ROSE, which combines State Estimator and Phasor Measurement Unit (PMU) data for on-line calculation and visualization of the current operating point and its proximity to the voltage stability boundary, thus giving RC operators an improved awareness of system stability and potentially alerting them to impending system emergencies. Peak will fully implement ROSE by September 15, 2015. Peak will train all RC operators on ROSE.

D. Compliance Monitoring

56. WECC and Peak shall make semi-annual reports to Enforcement and NERC, which may be independent or joint reports, for one year after the Effective Date of this Agreement. Enforcement and NERC may require one additional year of semi-annual

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reporting if circumstances indicate the need for further monitoring. The first semi-annual report for each entity shall cover the first six-month period after the Effective Date of this Agreement and shall be submitted to Enforcement and NERC staff within thirty days thereafter. The subsequent report(s) shall be due in six month increments thereafter. Each report shall detail the following: (1) actions taken as of the date of the report to satisfy the terms of the Agreement, including all Reliability Enhancements and (2) actions taken to improve reliability and/or reliability compliance, including investments in new measures and training activities during the reporting period. Peak shall also detail any additional possible violations, compliance exceptions, or self-logged issues of Reliability Standards by Peak identified by Peak or WECC or reported to WECC, and whether and how Peak has addressed those matters. The reports must include affidavits executed by officers of WECC and Peak, respectively, that the compliance reports are true and accurate and must also include corroborative documentation or other satisfactory evidence demonstrating or otherwise supporting the content of these reports. Corroborative documentation shall include, at a minimum, the Operational Practices Survey results and a description of any actions planned in response to the Operational Practices Survey results, or, in the alternative, the results of other applicable monitoring and a description of any actions planned in response to those results. If, after WECC and/or Peak have fulfilled the semi-annual reporting requirement, either entity has not yet completed or implemented its mitigation or reliability activities, it shall continue to update Enforcement and NERC semi-annually on the progress and completion of the mitigation or reliability activities not yet completed or implemented. Updates shall include corroborative documentation or other satisfactory evidence of progress, completion or implementation.

VI. TERMS

57. The “Effective Date” of the Agreement shall be the date on which the Commission issues an order approving the Agreement without material modification. When effective, the Agreement shall resolve any and all reliability claims relating to the September 8 event within the jurisdiction of the Commission, and that occurred on or before the Effective Date, as to WECC, Peak or any affiliated entity.

58. Commission approval of the Agreement without material modification shall release WECC and Peak and forever bar the Commission and NERC from holding WECC or Peak, any affiliated entity, and any successor in interest to WECC or Peak liable for any and all claims within the jurisdiction of the Commission, arising out of any and all reliability matters related to the September 8 event or conduct addressed and stipulated to in this Agreement, that occurred on or before the Agreement’s Effective Date.

59. Failure to make timely civil penalty payments or to comply with the Reliability Enhancements, mitigation and reliability activities, and monitoring agreed to herein, or

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any other provision of the Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act (FPA), 16 U.S.C. §792, *et seq.*, and may subject WECC to additional action under the enforcement provisions of the FPA.

60. Failure to comply with the Reliability Enhancements, mitigation and reliability activities, and monitoring agreed to herein, or any other provision of the Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act (FPA), 16 U.S.C. §792, *et seq.*, and may subject Peak to additional action under the enforcement provisions of the FPA.

61. If WECC does not make any portion of the civil penalty payment described above at the time(s) agreed by the parties, interest payable to the United States Treasury and NERC shall begin to accrue pursuant to the Commission's regulations at 18 C.F.R. § 35.19(a) (2) (iii) (2014) from the date that payment is due.

62. The Agreement binds WECC, Peak, and their agents, successors, and assignees. The Agreement does not create any additional or independent obligations on WECC or Peak, or any affiliated entity, its agents, officers, directors, or employees, other than the obligations identified in the Agreement.

63. The findings of violations detailed in the Agreement shall constitute prior violations for consideration in any future Commission or NERC enforcement proceeding against Peak or any successor.

64. The signatories to the Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer or promise of any kind by any member, employee, officer, director, agent or representative of Enforcement, NERC, WECC or Peak has been made to induce the signatories or any other party to enter into the Agreement.

65. Unless the Commission issues an order approving the Agreement in its entirety and without material modification, the Agreement shall be null and void and of no effect whatsoever, and Enforcement, NERC, WECC, and Peak shall not be bound by any provision or term of the Agreement, unless otherwise agreed to in writing by Enforcement, NERC, WECC and Peak.

66. WECC and Peak agree that the Commission's order approving the Agreement without material modification shall be a final and unappealable order assessing a civil penalty under the Federal Power Act. WECC and Peak waive findings of fact and conclusions of law, rehearing of any Commission order approving the Agreement without material modification, and judicial review by any court of any Commission order approving the Agreement without material modification.

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67. The Agreement can be modified only if in writing and signed by Enforcement, NERC, WECC and Peak, and any modifications will not be effective unless approved by the Commission.

68. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity and accepts the Agreement on the entity's behalf.

69. The undersigned representatives of WECC and Peak affirm that he or she has read the Agreement, that all of the matters set forth in the Agreement are true and correct to the best of his or her knowledge, information and belief, and that he or she understands that the Agreement is entered into by Enforcement and NERC in express reliance on those representations.

70. The Agreement may be signed in counterparts.

71. The Agreement is executed in quadruplicate, each of which so executed shall be deemed to be an original.

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Agreed to and accepted:

Larry Parkinson
Director, Office of Enforcement
Federal Energy Regulatory Commission

Date: 5/7/15

Charles A. Berardesco
Senior Vice President, General Counsel and Corporate Secretary
North American Electric Reliability Corporation

Date: 5/14/15

James B. Robb
Chief Executive Officer
Western Electricity Coordinating Council

Date: 6 MAY 2015

Gary Stephenson
President and Chief Executive Officer
Peak Reliability

Date: MAY 12, 2015

Document Content(s)

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151 FERC ¶ 61,175
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

Western Electricity Coordinating Council Docket No. IN14-11-000

ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued May 26, 2015)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) among the Office of Enforcement (Enforcement), the North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Peak Reliability (Peak). This order is in the public interest because it resolves on fair and reasonable terms an investigation of WECC (as the Reliability Coordinator (RC) for the Western Interconnection (WECC RC)), conducted by Enforcement in coordination with NERC and the Commission's Office of Electric Reliability (OER), into possible violations of Reliability Standards associated with WECC RC's oversight of a portion of the Bulk-Power System (BPS) and a blackout that occurred on September 8, 2011 (the September 8 event or the event). WECC agrees to pay a civil penalty of $16,000,000, of which $3,000,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $13,000,000 will be invested in reliability enhancement measures identified below that go above and beyond the Agreement's mitigation and reliability activities or what the Reliability Standards require (Reliability Enhancements). Peak did not exist as a separate entity at the time of the September 8 event, but is a party to the Agreement as the successor to WECC as the RC for the Western Interconnection. WECC and Peak also commit to certain mitigation and reliability activities, subject to compliance monitoring, as detailed in the Agreement.

I. Background

2. WECC is a non-profit, public service corporation and is not a load-serving entity. At the time of the event, WECC acted as both the Regional Entity (WECC RE) and the RC for the Western Interconnection. The WECC region at the time of the event extended from Canada to Mexico, was nearly 1.8 million square miles in size and served a population of 78 million. It included the Canadian provinces of Alberta and British Columbia, the northern part of Baja California, Mexico, the states of Washington,

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Oregon, California, Idaho, Nevada, Utah, Arizona, Colorado, Wyoming, and portions of Montana, South Dakota, New Mexico, and Texas.

3. WECC's RE and RC functions were organized separately, but reported to the same WECC executive management. WECC RC was a NERC Registered Entity, and was the highest level of authority responsible for the reliable operation of the Bulk Electric System (BES) in the Western Interconnection.

4. The RC of the Western Interconnection (formerly WECC RC, now Peak) is responsible for overseeing operation of the Western Interconnection in real time, receiving data from entities throughout the entire Interconnection, and providing high-level situational awareness for the entire system. The RC has the authority to prevent or mitigate emergency operating conditions in the next-day and real-time timeframes. The RC may issue directives to other functional entities to ensure reliable operations. The RC performs reliability analyses including next-day planning and real-time contingency analysis (RTCA) for the Western Interconnection. The RC may also assist transmission operators (TOPs) in mitigating equipment overloads and coordinating restoration plans, contingency plans, and reliability-related services.

5. As the RE, WECC or its delegate, among other things, monitors compliance of Registered Entities (including, formerly, WECC RC and currently, Peak) with the Reliability Standards, under delegated authority from NERC.

6. On March 16, 2007, in Order No. 693,[1] the Commission approved the initial Reliability Standards, which became mandatory and enforceable within the contiguous United States on June 18, 2007.

7. After the event, WECC sought approval from the Commission to establish a new entity to perform the RC and interchange authority (IA) functions in the Western Interconnection. The bifurcation of WECC into two separate entities, WECC and Peak, received final approval from the Commission on February 12, 2014.[2] With the Commission's approval, WECC sub-delegated the RC and IA functions in the Western Interconnection to Peak. WECC has retained its RE responsibilities.

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[1] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[2] *See North American Electric Reliability Corp.*, 146 FERC ¶ 61,092 (2014*), reh'g denied*, 147 FERC ¶ 61,064 (2014) (accepting compliance filings submitted by NERC and WECC and eliminating all final obstacles to bifurcation), appeal docketed *sub nom Edison Electric Institute v. FERC*, No. 14-1071 (D.C. Cir. May 9, 2014).

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8. WECC and Peak are subject to the Commission's regulation under section 215 of the Federal Power Act (FPA).[3]

9. The investigation of WECC arose out of a system disturbance that occurred on the afternoon of September 8, 2011 in the Pacific Southwest, which resulted in cascading outages and left approximately 2.7 million customers (equivalent to five million or more individuals) without power, some for multiple hours extending into the next day. The total load loss for the event was in excess of 30,000 MWh. The event started with a three-phase fault which led to the loss of Arizona Public Service Company's (APS) Hassayampa-N. Gila 500 kV transmission line (H-NG). This transmission line is a segment of the Southwest Power Link (SWPL), a major transmission corridor transporting power in an east-west direction, from generators in Arizona, through Imperial Irrigation District's (IID) service territory, into Southern California.

10. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the electric system in the Pacific Southwest and Southern California, increasing flows through lower voltage systems parallel to the SWPL as power continued to flow on a hot day during hours of peak demand.

11. These redistributed flows traveled through IID's and Western Area Power Administration-Desert Southwest Region's (Western-DSW) facilities, onto WECC Path 44, an aggregation of five 230 kV transmission lines that deliver power in a north-south direction from Southern California Edison Company's (SCE) territory in Los Angeles to San Diego Gas & Electric (SDG&E). The increased power flows parallel to the SWPL, together with lower than peak generation levels in California and Mexico, led to significant voltage deviations and transmission equipment overloads. The flow redistributions, voltage deviations, and resulting overloads had a cascading effect, as transmission and generation equipment tripped offline in a relatively short time period. Just seconds before the blackout, Path 44 carried all flows into San Diego as well as parts of Arizona and Mexico. This excessive loading on Path 44 initiated an intertie separation scheme owned and operated by SCE at the San Onofre switchyard. The California Independent System Operator (CAISO) is responsible for many of the TOP functions for SCE under a Coordinated Functional Registration. Initiation of the intertie separation scheme at the San Onofre switchyard separated SDG&E from Path 44, contributed to tripping the San Onofre Nuclear Generating Station nuclear units offline, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's Baja California Control Area in Mexico.

12. WECC RC was the highest reliability authority at the time of the event and maintained a wide-area view of the entire Interconnection. WECC RC was staffed with

[3] 16 U.S.C. § 824o (2012).

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two operators (one real-time operator and one study desk operator) in each of its two regional offices at the time of the event.

13. Promptly after WECC RC's alarms reflected the loss of H-NG, WECC RC operators contacted APS, the operator of H-NG, to discuss the status of H-NG. APS operators informed WECC RC operators that APS could restore H-NG within minutes. WECC RC operators relied on the statement by APS operators that APS could restore H-NG within minutes, and issued no reliability directives in connection with the event, which lasted only 11 minutes (not including restoration). WECC RC and APS operators did not discuss the existing large phase angle difference between Hassayampa and N. Gila that needed to be addressed before H-NG could be returned to service.

14. Prior to the event, WECC RC conducted a next-day study for the entire Western Interconnection, using a model that included, among other equipment, IID's 230 /92 kV transformers. However, the study did not include the effects of the S-Line remedial action scheme (RAS) and separation scheme at the San Onofre switchyard. At the time of the event, WECC excluded from its interpretation of the definition of special protection systems/remedial action schemes (SPSs/RASs) certain types of protection systems, including the S-Line RAS and the separation scheme at the San Onofre switchyard. As a result, WECC RC and the TOPs did not study those systems and schemes. Additionally, WECC RC only reviewed the TOPs' next-day studies when it identified an issue in its own next-day study. WECC RC did not review IID's next-day study for September 8.

15. WECC RC was responsible for monitoring all critical facilities in the Western Interconnection, which may include facilities below 100 kV, as necessary to ensure that at any time, regardless of unplanned events, it was able to determine system operating limits (SOLs) and interconnection reliability operating limits (IROLs), and to know the status of all critical facilities whose failure could result in an SOL or IROL exceedance. On September 8, a WECC RC operator was alerted by an alarm in real time to the fact that IID's 230/92 kV Coachella Valley transformers had tripped (WECC RC had real-time visibility of the transformers even though they were not classified as BES facilities at the time), but was unaware that those transformers tripping could result in a previously unidentified IROL. The September 8 event also exposed SOLs that were previously unrecognized by WECC RC, by revealing that operating WECC Path 44 to an SOL of 2,200 MW, and H-NG (a portion of WECC Path 49), to a limit of 1800 MW, would expose the WECC RC area to cascading outages.

16. Prior to the event, the Operating Practices Subcommittee of WECC's Operating Committee stated an operating philosophy that no IROLs existed under normal operating conditions. As a result, WECC RC did not recognize any IROLs in the Western Interconnection. Following the exposure of the Coachella Valley 230/92 transformers IROL by the September 8 event, WECC RC has since recognized the existence of several IROLs in the Western Interconnection, and Peak continues to analyze the Interconnection

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for additional IROLs. At the time of the event WECC RC also delegated to TOPs the responsibility for identifying criteria that determine when violating an SOL qualifies as an IROL.

17. WECC RC was aware of post-contingency overloads within Western-DSW and IID, but did not alert Western-DSW and IID to these potential transmission problems.

II. Investigation

18. On September 9, 2011, the Commission and NERC announced a joint inquiry to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. The inquiry team, comprised of Commission and NERC staff, used on-site visits and interviews, detailed computer modeling, event simulations, and system analyses to make its findings and recommendations for preventing similar events in the future. The inquiry determined that entities responsible for planning and operating the BPS were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency. On May 1, 2012, the inquiry team published a report entitled *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (the Report), which is hereby incorporated by reference.[4] The Report discusses a detailed sequence of events, simulations, and findings related to the causes of the cascading outages. The Report also makes twenty-seven recommendations related to next-day planning, seasonal planning, near- and long-term planning, situational awareness, consideration of BES equipment, SOLs and IROLs, and protection systems.

19. Following publication of the Report, Enforcement, OER, and NERC staff reviewed the data gathered during the inquiry for compliance implications. At the direction of the Commission, Enforcement initiated non-public investigations of several entities, including WECC, under Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014), which were conducted jointly with NERC.

20. Enforcement and NERC determined that WECC violated the Facilities Design, Connection and Maintenance (FAC) and Interconnection Reliability Operations and Coordination (IRO) groups of Reliability Standards. The IRO Reliability Standards "detail the responsibilities and authorities of [an RC]," and "establish requirements for data, tools and wide-area view, all of which are intended to facilitate [an RC's] ability to perform its responsibilities and ensure the reliable operation of the interconnected grid."[5] The FAC standards at issue aim to ensure that SOLs are determined based on an established methodology.

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[4] *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

[5] Order No. 693 at P 888.

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21. Enforcement and NERC determined that WECC RC violated nine Requirements of five Reliability Standards: FAC-011-2 R3; FAC-014-2 R1; IRO-003-2 R1 and R2; IRO-004-1 R1; and IRO-005-2 R5, R9, R12, and R15—stemming from its role in the September 8 event.

22. Enforcement and NERC staff determined that WECC RC violated IRO-003-2 R1 and R2 because WECC RC was unaware that IROLs such as the Coachella Valley 230-92 kV transformers existed in its control area, and thus did not determine or prevent IROL violations on September 8, 2011.

23. Enforcement and NERC staff determined that WECC RC violated IRO-004-1 R1 and IRO-005-2 R5, R9, and R15 because it did not identify the cause of potential and actual SOL and IROL violations on Paths 44 and 49, mitigate the violations, and alert impacted TOPs and BAs in its area.

24. Enforcement and NERC staff determined that WECC RC violated IRO-005-2 R12 because it was not aware of the impact of the S-line RAS and separation scheme at the San Onofre switchyard.

25. Enforcement and NERC staff determined that WECC RC violated FAC-011-2 R3 and FAC-014-2 R1 as a result of inadequacies in its SOL methodology that resulted in the establishment of unreliable SOLs for Paths 44 and 49 and the failure to identify IROLs.

III. Stipulation and Consent Agreement

26. Enforcement, NERC, WECC and Peak resolved this matter by means of the attached Agreement. WECC stipulates to the facts recited in the Agreement and agrees to pay a civil penalty of $16,000,000, of which $3,000,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $13,000,000 will be invested by WECC and Peak in Reliability Enhancements that go above and beyond the requirements of the Reliability Standards, as described in the Agreement. WECC and Peak also agree to mitigation and reliability activities, and to submit to compliance monitoring, as specified in the Agreement. WECC neither admits nor denies that its actions constituted violations of the Reliability Standards.

27. In determining the appropriate sanction, Enforcement considered that WECC has made significant efforts to date to address reliability concerns identified in the inquiry and investigation and also by WECC on its own initiative. WECC also cooperated with Enforcement and NERC during the investigation.

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IV. Determination of the Appropriate Sanctions

28. The civil penalty amount is consistent with the Penalty Guidelines.[6] Enforcement considered that the event caused a loss of 10,000 or more MWh of firm load, and WECC was allocated a share of the base penalty due to its role as the RC. WECC RC also had a prior history of violations of the Reliability Standards, including two violations based on conduct substantially similar to that at issue in this event.[7] The civil penalty amount reflects credit for WECC's cooperation during the course of the investigation, as well as credits for avoiding a trial-type hearing and having an effective compliance program.

29. The Commission concludes that the penalties and other sanctions set forth in the Agreement are a fair and equitable resolution of this matter and are in the public interest. The Commission also concludes that the reliability enhancement, mitigation and reliability activities set forth in the Agreement will enhance the reliability of the BPS and are therefore also fair and in the public interest.

The Commission orders:

The attached Stipulation and Consent Agreement is hereby approved without modification.

By the Commission. Chairman Bay is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

[6] *Enforcement of Statutes, Orders, Rules and Regulations,* 132 FERC ¶ 61,216 (2010).

[7] *Western Electricity Coordinating Council,* 136 FERC ¶ 61,020 (2011) (including lack of awareness of SPS within its RC area under IRO-005-1 R12); Notice of Penalty, Docket No. NP11-259-000, September 9, 2011 (including failure to coordinate with TOPs to mitigate SOL exceedance under IRO-005-1 R9).

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Western Electricity Coordinating Council) Docket No. IN14-11-000

STIPULATION AND CONSENT AGREEMENT

I. INTRODUCTION

1. Staff of the Office of Enforcement (Enforcement) of the Federal Energy Regulatory Commission (Commission), the North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Peak Reliability (Peak) enter into this Stipulation and Consent Agreement (Agreement) to resolve a non-public investigation conducted by Enforcement and NERC pursuant to Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014). The investigation examined possible violations of NERC Reliability Standards by WECC as the Reliability Coordinator (RC) for the Western Interconnection (WECC RC)) related to a system event in the Pacific Southwest on September 8, 2011 (September 8 event or event). WECC neither admits nor denies that WECC RC violated the Reliability Standards described in the Agreement, but agrees to pay a total civil penalty of $16,000,000, of which $3,000,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $13,000,000 will be invested in reliability enhancement measures identified below that go above and beyond the Agreement's mitigation and reliability activities or what the Reliability Standards require (Reliability Enhancements). Peak did not exist as a separate entity at the time of the September 8 event, but is a party to the Agreement as the successor to WECC as the RC for the Western Interconnection. WECC and Peak also commit to certain measures, subject to compliance monitoring, as detailed in the Agreement.

II. STIPULATED FACTS

2. Enforcement, NERC, and WECC and Peak hereby stipulate and agree to the following facts.

A. WECC

3. WECC is a non-profit, public service corporation and is not a load-serving entity. WECC is funded by assessments to load-serving entities, among others. At the time of the event, WECC acted as both the Regional Entity (WECC RE) and the RC for the Western Interconnection. These functions were organized separately, but reported to the same WECC executive management. WECC RC was a NERC Registered Entity, and was the highest level of authority responsible for the reliable operation of the Bulk Electric System (BES) in the Western Interconnection.

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4. The RC of the Western Interconnection (formerly WECC RC, now Peak) is responsible for overseeing operation of the Western Interconnection in real time, receiving data from entities throughout the entire Interconnection, and providing high-level situational awareness for the entire system. The RC has the authority to prevent or mitigate emergency operating conditions in the next-day and real-time timeframes. The RC may issue directives to other functional entities to ensure reliable operations. The RC performs reliability analyses including next-day planning and real-time contingency analysis (RTCA) for the Western Interconnection. The RC may also assist transmission operators (TOPs) in mitigating equipment overloads and coordinating restoration plans, contingency plans, and reliability-related services.

5. As the RE, WECC or its delegate, among other things, monitors compliance of Registered Entities (including, formerly, WECC RC and currently, Peak) with the Reliability Standards, under delegated authority from NERC.

6. After the event, WECC sought approval from the Commission to establish a new entity to perform the RC and interchange authority (IA) functions in the Western Interconnection. The bifurcation of WECC into two separate entities, WECC and Peak, received final approval from the Commission on February 12, 2014.[1] With the Commission's approval, WECC sub-delegated the RC and IA functions in the Western Interconnection to Peak. WECC has retained its RE responsibilities.

B. Event Description

7. During an 11-minute period on the afternoon of September 8, 2011, a system disturbance occurred in the Pacific Southwest, resulting in cascading outages and leaving approximately 2.7 million customers without power, some for multiple hours extending into the next day. The total load loss for the event was in excess of 30,000 MWh. The event started with a three-phase fault which led to the loss of Arizona Public Service's (APS) Hassayampa-N. Gila 500 kV transmission line (H-NG). This transmission line is a segment of the Southwest Power Link (SWPL), a major transmission corridor transporting power in an east-west direction, from generators in Arizona, through the service territory of Imperial Irrigation District (IID), into Southern California.

8. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the electric system in the Pacific Southwest and Southern California, increasing flows through lower voltage systems parallel to the SWPL as power continued to flow on a hot day during hours of peak demand.

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[1] *See North American Electric Reliability Corp.*, 146 FERC ¶ 61,092 (2014*), reh'g denied*, 147 FERC ¶ 61,064 (2014) (accepting compliance filings submitted by NERC and WECC and eliminating all final obstacles to bifurcation), appeal docketed *sub nom Edison Electric Institute v. FERC*, No. 14-1071 (D.C. Cir. May 9, 2014).

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9. These redistributed flows traveled through IID's and Western Area Power Administration – Desert Southwest Region's facilities (Western-DSW), onto WECC Path 44, an aggregation of five 230 kV transmission lines that deliver power in a north-south direction from Southern California Edison Company's (SCE) territory in Los Angeles to San Diego Gas and Electric (SDG&E). The increased power flows parallel to the SWPL, together with lower than peak generation levels in California and Mexico, led to significant voltage deviations and transmission equipment overloads. The flow redistributions, voltage deviations, and resulting overloads had a cascading effect, as transmission and generation equipment tripped offline in a relatively short time period. Just seconds before the blackout, Path 44 carried all flows into San Diego as well as parts of Arizona and Mexico. This excessive loading initiated an intertie separation scheme owned and operated by SCE at the San Onofre switchyard. The California ISO (CAISO) is responsible for many of the TOP functions for SCE under a Coordinated Functional Registration. Initiation of the intertie separation scheme at the San Onofre switchyard separated SDG&E from Path 44, contributed to tripping the San Onofre Nuclear Generation Station nuclear units offline, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's Baja California Control area.

10. WECC RC was the highest reliability authority at the time of the event and maintained a wide-area view of the entire Interconnection. WECC RC was staffed with two operators (one real-time operator and one study desk operator) in each of its two regional offices at the time of the event.

11. Promptly after WECC RC's alarms reflected the loss of H-NG, WECC RC operators contacted APS, the operator of H-NG, to discuss the status of H-NG. APS operators informed WECC RC operators that APS could restore H-NG within minutes. WECC RC operators relied on the statement by APS operators that APS could restore H-NG within minutes, and issued no reliability directives in connection with the event, which lasted only 11 minutes (not including restoration). WECC RC and APS operators did not discuss the existing large phase angle difference between Hassayampa and N. Gila that needed to be addressed before H-NG could be returned to service.

12. Prior to the event, WECC RC conducted a next-day study for the entire Western Interconnection, using a model that included, among other equipment, IID's 230 /92 kV transformers. However, the study did not include the effects of the S-Line remedial action scheme (RAS) and separation scheme at the San Onofre switchyard. At the time of the event, WECC excluded from its interpretation of the definition of special protection systems/remedial action schemes (SPSs/RASs) certain types of protection systems, including the S-Line RAS and the separation scheme at the San Onofre switchyard, among others. As a result, WECC RC and the TOPs did not study those systems and schemes. Additionally, WECC RC only reviewed the TOPs' next-day studies when it identified an issue in its own next-day study. WECC RC did not review IID's next-day study for September 8.

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13. WECC RC was responsible for monitoring all critical facilities in the Western Interconnection, which may include facilities below 100 kV, as necessary to ensure that at any time, regardless of unplanned events, it was able to determine system operating limits (SOLs) and interconnection reliability operating limits (IROLs), and to know the status of all critical facilities whose failure could result in an SOL or IROL exceedance. On September 8, a WECC RC operator was alerted by an alarm in real time to the fact that IID's 230/92 kV Coachella Valley transformers had tripped (WECC RC had real-time visibility of the transformers even though they were not classified as BES facilities at the time), but was unaware that those transformers tripping could result in a previously unidentified IROL. The September 8 event also exposed SOLs that were previously unrecognized by WECC RC, by revealing that operating WECC Path 44 to an SOL of 2,200 MW, and H-NG (a portion of WECC Path 49) to a limit of 1800 MW, would expose the WECC RC area to cascading outages.

14. Prior to the event, the Operating Practices Subcommittee of WECC's Operating Committee stated an operating philosophy that no IROLs existed under normal operating conditions. As a result, WECC RC did not recognize any IROLs in the Western Interconnection. Following the exposure of the Coachella Valley 230-92 transformers IROL by the September 8 event, WECC RC has since recognized the existence of several IROLs in the Western Interconnection, and Peak continues to analyze the Interconnection for additional IROLs. At the time of the event WECC RC also delegated to TOPs the responsibility for identifying criteria that determine when violating an SOL qualifies as an IROL.

15. WECC RC was aware of post-contingency overloads within Western-DSW and IID, but did not alert Western-DSW and IID to these potential transmission problems.

III. INQUIRY AND INVESTIGATION

16. On September 9, 2011, the Commission and NERC announced a joint inquiry to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. The inquiry team, comprised of Commission and NERC staff, used on-site visits and interviews, detailed computer modeling, event simulations, and system analyses to make its findings and recommendations for preventing similar events in the future. The inquiry determined that entities responsible for planning and operating the bulk-power system (BPS) were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency. On May 1, 2012, the inquiry team published a report entitled *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (the Report), which is hereby incorporated by reference.[2] The Report discusses a detailed sequence of events, simulations, and findings

[2] *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

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related to the causes of the cascading outages. The Report also makes twenty-seven recommendations related to next-day planning, seasonal planning, near- and long-term planning, situational awareness, consideration of BES equipment, SOLs and IROLs, and protection systems.

17. Following publication of the Report, Enforcement and NERC reviewed the data gathered during the inquiry for compliance implications. As a result of that review, Enforcement and NERC initiated non-public investigations of several entities, including WECC, under Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014).

18. Enforcement and NERC determined that WECC violated nine Requirements of five Reliability Standards, and found these violations undermined the reliability of the BPS and contributed to the September 8 event. Enforcement and NERC recognized, however, that after the event, and during the inquiry and investigation, WECC voluntarily began making improvements in its planning and operations, and implementing recommendations from the Report, that addressed many of the findings arising from the Report. WECC established an online Dashboard to track its progress. In addition, WECC cooperated with Enforcement and NERC during the investigation.

19. As part of the investigation, Enforcement and NERC reviewed WECC's compliance program (as it existed at the time of the event) and found that WECC satisfied the criteria for an effective compliance program under the Commission's Penalty Guidelines.[3] Enforcement and NERC considered the elements of WECC's compliance program set forth in this paragraph. At the time of the September 8 event, WECC RC had a formal compliance program. WECC RC had a designated Compliance Manager, who had direct access to WECC senior executives and, as necessary, the WECC board. All WECC team members were expected to collaborate in the implementation of practices and policies meant to ensure compliance with all rules and regulations. All WECC team members underwent mandatory training on the Reliability Standards relevant to their positions, as well as training on the benefits of compliance and the risks of non-compliance. Peak has built upon WECC's compliance program. Under Peak's current program, the Compliance Director reports directly to the President and Chief Executive Officer, with access to the Chair of the Board of Directors as needed. The Compliance Director is directly supported by an Operations Compliance Specialist and CIP Compliance Specialist, with all Peak team members required to collaborate to develop and implement policies, procedures, work practices and technologies to ensure compliance with the Reliability Standards. Peak has a "Compliance Open Door Policy" that encourages all team members to bring compliance issues to the attention of management, whether through direct report to the Compliance Director, or anonymous

[3] *Enforcement of Statutes, Orders, Rules and Regulations,* 132 FERC ¶ 61,216, § 1B2.1 (2010).

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reporting to a third-party compliance reporting service provider. All Peak team members undergo mandatory compliance training relevant to their positions, and new hires are trained on the Reliability Standards, benefits of compliance, risks of non-compliance, the Compliance Open Door Policy, and Peak's rewards for compliance and disciplinary measures for non-compliance.

IV. ENFORCEMENT AND NERC FINDINGS OF VIOLATIONS

20. Enforcement and NERC staff determined that WECC RC violated the following Requirements of the Reliability Standards: FAC-011-2 R3; FAC-014-2 R1; IRO-003-2 R1 and R2; IRO-004-1 R1; and IRO-005-2 R5, R9, R12, and R15.[4] Enforcement and NERC staff determined that WECC RC violated IRO-003-2 R1 and R2 because WECC RC was unaware that IROLs existed in its control area and were violated on September 8, 2011. Enforcement and NERC staff determined that WECC RC violated IRO-004-1 R1 and IRO-005-2 R5, R9, and R15 because it did not identify the cause of potential and actual SOL and IROL violations, mitigate the violations, and alert impacted TOPs and Balancing Authorities (BAs) in its area. Enforcement and NERC staff determined that WECC RC violated IRO-005-2 R12 because it was not aware of the impact of the S-line RAS and separation scheme at the San Onofre switchyard. Lastly, Enforcement and NERC staff determined that WECC RC violated FAC-11-2 R3 and FAC-014-2 R1 for inadequacies in its SOL methodology that resulted in the establishment of unreliable SOLs and the failure to identify IROLs.

V. REMEDIES AND SANCTIONS

21. WECC stipulates to the facts as described in Section II of this Agreement, but neither admits nor denies Enforcement's and NERC's findings that WECC RC violated the Reliability Standards specified in Section IV. For purposes of settling any and all disputes within the jurisdiction of the Commission arising from any and all reliability matters related to the September 8 event, or Enforcement's and NERC's investigation, WECC agrees to the remedies and sanctions set forth in the following paragraphs assigned to WECC, including the entire cash payment to Treasury and NERC, and Peak agrees to the remedies assigned to Peak. Pursuant to the Revised Reliability Coordinator and Interchange Authority Agreement between the Western Electricity Coordinating Council and Peak Reliability (RC Agreement), Peak is responsible for reporting obligations and enforcement conditions relating to its role as the RC, and WECC is responsible for reporting obligations and enforcement conditions relating to its role as the RE.

[4] As noted in paragraphs 1 and 21, WECC neither admits nor denies the findings by Enforcement and NERC regarding violations of the Reliability Standards, and use of the term mitigation is not meant to imply otherwise.

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A. Civil Penalty

22. WECC shall pay a total civil penalty of $16,000,000, of which $3,000,000 shall be paid, divided in equal amounts, to the United States Treasury and NERC. $1,000,000, divided equally between the United States Treasury and NERC, shall be due within ten days of the Effective Date of the Agreement. $1,000,000, divided equally between the United States Treasury and NERC, shall be due within one year from the Effective Date and $1,000,000, divided equally between the United States Treasury and NERC, shall be due within two years of the Effective Date. Enforcement and NERC agree to give WECC a partial civil penalty offset for the remaining $13,000,000 in exchange for WECC and Peak implementing the Reliability Enhancements as set forth in section V.B. The value of the Reliability Enhancements is expected to substantially exceed the amount of the offset.

B. Reliability Enhancements

23. In exchange for the $13,000,000 offset, WECC and Peak have completed or shall complete the following Reliability Enhancements:

a. WECC RC partially increased, and Peak has continued to and shall increase, staffing of the RC function from the staffing in effect on September 8, 2011, by 61 full-time equivalent positions, including 18 RC operators. Peak shall maintain the additional 18 RC operator positions at least through December 31, 2016; and

b. WECC completed bifurcation of the RE function of WECC from the RC function, with the RC function sub-delegated to Peak on February 14, 2014.

24. WECC and Peak will provide Enforcement and NERC with satisfactory evidence that investments to date in the Reliability Enhancements have substantially exceeded $13,000,000.

C. Completed and Required Mitigation and Reliability Activities

25. WECC and Peak, respectively, commit to the designated actions in this Section V.C. As indicated below, WECC and Peak affirm that they have already completed most of the mitigation and reliability activities, and shall complete all remaining mitigation and reliability activities no later than one year after the Effective Date of the Agreement, unless otherwise stated in Section V.C. WECC and Peak shall continue operating consistent with the completed and required mitigation and reliability activities, until they implement improved practices and procedures in accordance with the Reliability Standards in existence now or in the future. Until WECC and Peak have completed all mitigation and reliability activities and Reliability Enhancements, any material alterations in the mitigation and reliability activities set forth in Section V.C. shall be approved by

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Enforcement and NERC staff, such approval not to be unreasonably withheld. WECC and Peak will individually or jointly report on the status of all mitigation and reliability activities described in this Section V.C. and submit evidence of progress and/or completion in their compliance monitoring reports to be submitted to Enforcement and NERC pursuant to Section V.D of this Agreement. WECC and Peak agree to work cooperatively to provide Enforcement and NERC staff with information necessary to confirm that all mitigation and reliability activities have been completed.

i. Seasonal, Next-Day and Current-Day Planning

26. Peak now shares its next-day study, as well as study inputs such as outages and interchange, electronically on a daily basis with all WECC entities that have executed the Universal Data Sharing Agreement (UDSA). WECC RC and Peak created additional formats for TOPs to review the RC studies, including Power System Simulator for Engineering (PSS/E) and Positive Sequence Load Flow (PSLF). After the September 8 event, WECC and Peak obtained executed UDSAs from all Western Interconnection BAs, TOPs and Transmission Owners (TOs). Peak and the TOPs are engaged in negotiations to renew the UDSA. The Peak Board of Directors has established a bridge policy to ensure that access to data sharing is maintained during the negotiations.

27. Peak has improved the forecasting of interchange between TOPs by working with BAs to identify the reasons for forecasting errors, and to improve the unit commitment data provided to the RC. Peak worked with the BAs to address unit commitment data issues that were identified by a task force that reviewed input data issues related to the RC's next-day studies. All data issues related to unit commitment and interchange forecasting identified by the task force have been remedied.

28. By June 30, 2015, WECC will issue a guideline outlining best practices for next-day studies, which will be posted on the WECC website. WECC will monitor the effectiveness of this guideline through a next-day study working group and the annual Operational Practices Survey, or other appropriate means.

29. In February 2014, WECC issued its "Pre/Post-Contingency Guideline," which guides TOPs to take pre-contingency mitigation measures when potential post-contingency conditions could exceed the TOPs' highest emergency rating for a facility. The Guideline also reminds TOPs to consider the time necessary to take mitigation actions, and to consider the effect of relays that automatically isolate facilities without providing time for mitigating measures. WECC has posted this guideline on the WECC website, and will monitor its effectiveness through the annual Operational Practices Survey, or other appropriate means.

30. Peak shall coordinate the seasonal planning process for its RC area. Seasonal planning by TOPs in the Western Interconnection begins with the operational base cases prepared by WECC. WECC shall continue to prepare operational base cases. WECC

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and Peak shall cooperate, to the extent applicable, to gather information from TOPs to update the operational base cases. WECC RC and Peak have worked with the sub regional study groups to facilitate a consistent method for seasonal planning, including consistency in system conditions to be evaluated and consistency in process. WECC RC also worked with the sub regional study groups to improve coordination between seasonal study planners and operators. Peak shall require, per its SOL methodology and seasonal coordination process, that the seasonal planning for the Western Interconnection includes all critical internal and external conditions and contingencies, including generation and transmission outages, transfers, and demand patterns, including non-peak demand patterns. Critical internal and external facilities may be sub-100 kV, if they impact the BES. To the extent required by changes to the Reliability Standards related to planning, Peak will consult with FERC and NERC on how to satisfy the measures contained in this paragraph.

31. WECC has developed a procedure to perform N-1 contingency analysis on operational base cases for the Western Interconnection. WECC will implement this procedure by June 30, 2015, and will provide the results of its analysis to the area coordinators within 30 days after WECC completes its analysis.

j. Near- And Long-Term Planning

32. WECC established the Planning Coordinator Function Task Force to identify the current Planning Coordinator (PC) issues in the Western Interconnection, evaluate gaps in PC coverage in the Western Interconnection and to develop a methodology, procedures and implementation plan for addressing the PC issues in the Western Interconnection. In addition, using the results of a survey issued to registered PCs, WECC has identified those facilities within each current PC area, as well as facilities in areas for which no PC has been identified. WECC shall provide the Planning Coordinator Function Task Force's report (and any other deliverables) to Enforcement and NERC within 7 days of completion by the Task Force. After receipt of the report and deliverables, WECC, Peak, and FERC and NERC staff shall confer and cooperate in order to reach an agreement on a solution for the PC issues in the Western Interconnection, especially the gaps in PC coverage and seams issues.[5]

33. In July, 2014, WECC issued a BES Inclusion Guideline, which recognized that non-BES, or sub-100 kV, facilities may be important to the reliability of the Interconnection. The Guideline helps registered entities identify such facilities, and encourages, but does not require, registered entities to consider facilities for inclusion in

[5] Seams issues refers to the fact that transmission lines, interchange and loop flow patterns, among other characteristics of the BES, cross the boundaries between entities or sub regional groups, and thus may not be consistently analyzed by any individual entity or sub regional group.

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the BES through the NERC exception procedures. Among other situations that might qualify a non-BES facility for inclusion through the NERC exception procedures are facilities identified as a significant contributing factor in an event analysis report, or where the facility's single-contingency outage changes the flow on any BES element by more than 10 percent. WECC will monitor the effectiveness of the guideline through its annual Operational Practices Survey, or other appropriate means.

k. Protection Systems

34. Peak has included 239 additional RASs, and greater specificity about the existing RASs, in the models used for Peak's RTCA. Peak has also added 212 additional RASs to its Supervisory Control and Data Acquisition (SCADA) displays, and 4701 additional RAS Inter-Control Center Communication Protocol points, since the event.

35. By March 31, 2016, WECC will have developed the capability for entities to model RASs so that they can be added to its powerflow base cases. By June 30, 2016, WECC will update the Data Preparation Manual to include the requirement for data submitters to include RAS models in their submittal to WECC. WECC will produce the first powerflow base case to include RAS models by July 2016. By June 30, 2017, all WECC base cases shall include all (1) RASs, and (2) overcurrent protection relays with inter-TOP impact, known to WECC to exist in the Western Interconnection as of the Effective Date. In the interim, WECC collected and posted some data on RASs and relays with inter-TOP impact so that entities can model those impacts until those RASs and relays are modeled in the WECC base cases. Any RASs installed in the Western Interconnection after June 30, 2016 and known to WECC to exist shall be modeled in the base cases as soon as practicable in coordination with WECC's established base case production schedule.

36. WECC developed and adopted the Regional Criterion entitled "Remedial Action Scheme Review and Assessment Plan, PRC-(012 through 14)-WECC-CRT-2," which became effective January 1, 2014 (an earlier version became effective in October 2011). This criterion requires TOs, Generator Owners and Distribution Providers to submit data on RASs initially and before putting any changes or new RASs in service, to review the information in WECC's Remedial Action Scheme Database annually for accuracy, and to assess their RASs for operation, coordination, and effectiveness at least once every five years, among other requirements. This criterion also requires WECC's Remedial Action Scheme Reliability Subcommittee (RASRS) to review each RAS submitted to the RASRS for compliance with designated Reliability Standards, including Standards within the Transmission Planning and Protection Systems groups. As a result of this criterion, WECC has gathered data on multiple existing and new schemes. In addition, the RASRS chair issued a data request to all Western Interconnection TOPs requesting them to provide information on any tie line schemes or safety nets within their systems. That effort identified 25 additional RASs from seven entities that were incorporated into the Remedial Action Scheme Database. The information collected through the criterion will

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facilitate the WECC modeling process and assist in the identification of interaction among RASs.

37. WECC prepared a white paper on "The Recognition of Power Plant Control, Protection and Operation in Transmission Simulation Studies," which was posted on the WECC website.

38. In November, 2012, WECC issued its Guideline for Protection System Loadability. The guideline encourages TOPs to set load-responsive relays that are operated in parallel with the BES, but not subject to Reliability Standard PRC-023, to use one of the setting criteria from PRC-023. The Guideline also addresses phase angle differences used when reclosing a breaker, encouraging the TOPs to provide visibility of the phase angle difference by means that could include planning studies, State Estimator, Real-time Contingency Analysis (RTCA), Phasor Measurement Units, or synch check relays. WECC posted this guideline on the WECC website, and will monitor its effectiveness through the annual Operational Practices Survey, or other appropriate means.

l. Angular Separation

39. Since September 2011, WECC RC and Peak have improved the ability of the RC to estimate phase angle differences. Peak can monitor estimated or expected (post-contingency) phase angles using Real-time State Estimation and RTCA. A procedure exists, called *Monitoring Heavy E-W Flows on SWPL*, which describes action to be taken by the RC operator when exceeding phase angle line reclosure limits (synch check relay thresholds) on the SWPL. In addition to its focused monitoring of the phase angles on the SWPL, Peak also monitors fifteen other node-pairs in the Western Interconnection for, among other things, excessive phase angles. If a relevant line is open and results in the exceedance of a node-pair phase angle limit, Peak RC System Operators will see that exceedance in Peak's Energy Management System (EMS) applications. An actual exceedance of a node-pair phase angle limit is detected and reported in Peak's Real-time State Estimation. A post-contingency exceedance of a node-pair phase angle limit is detected and reported in Peak's RTCA and study contingency analysis applications. The node-pair phase angle limits currently implemented in Peak's EMS inform the RC System Operators that the relevant line cannot be reclosed because of the excessively high phase angle.

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m. System Operating Limits and Interconnection Reliability Operating Limits

40. After September 8, 2011, WECC began using a new SOL methodology, and further refined that methodology with its "Phase II SOL Methodology," Revision 7.0 of the SOL Methodology for the Operations Horizon, which became effective in March 2014. Among other things, the SOL Methodology currently in use by TOPs in the Western Interconnection and Peak instructs entities to assess projected system conditions as real time approaches to establish SOLs, and includes criteria for identifying the subset of SOLs that qualify as IROLs in real time, as well as a clearer definition of what is included in an SOL. The SOL methodology requires TOPs and the RC to operate in real time to the most restrictive of Facility Ratings, voltage limits, voltage stability limits, transient stability limits or WECC Path Ratings. Prior to the event, some TOPs operated only to Path Ratings or seasonally-determined SOLs. The SOL methodology also requires TOPs to use models for establishing SOLs and IROLs that include the entire WECC RC area, to include critical modeling details from other RC areas that would impact the facilities being studied, to model parallel sub-100 kV facilities (e.g., the Coachella Valley transformers), to include RASs/SPSs in their models where feasible, and to consider the impact of SPS/RAS actions when establishing SOLs and IROLs. Current IROLs recognized by Peak are posted online in the secure area of peakrc.org.

41. Peak shall make the following modifications to the SOL Methodology for the Operations Horizon:

a. Peak shall not exclude all load loss due to RAS/SPS actions for the purpose of determining whether an IROL exists, because to do so would have allowed the Coachella Valley transformers to elude recognition as an IROL; and

b. Peak shall justify the reason for the 1,000 MW cut-off for SOLs to be IROLs or establish a cut-off with technical justification.

n. Situational Awareness

42. Peak runs its RTCA every five minutes and Peak's RTCA results and certain State Estimator Savecases are immediately available to all TOPs and BAs in real time in the secure area of peakrc.org.

43. WECC RC began flagging and alarming the two Coachella Valley transformers in its RTCA shortly after the September 8, 2011 event. Peak shall continue to flag and alarm the Coachella Valley transformers.

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44. WECC RC and Peak have allowed TOPs to view the Coordinated Outage System once the TOPs executed the UDSA. All current TOPs have now executed the UDSA.[6]

45. WECC and Peak have increased real-time data sharing among TOPs by developing the WECC Operations Network guideline. WECC has posted this guideline on the WECC website, and will monitor its effectiveness through the annual Operational Practices Survey, or other appropriate means.

46. Peak has modified its data request to require each TOP to provide telephone notification to Peak when the TOP loses real-time data or RTCA. Peak will modify the Data Request to require notification either by telephone or by WECCNET, if possible.

47. WECC has issued a Real-Time Tools Guideline. Among other recommendations for best practices, it guides TOPs on the scope of their network model (to allow identification of external contingencies, for example), on how often to update their state estimator (every 10 minutes) and RTCA (at least every 30 minutes). WECC has posted this guideline on the WECC website, and will monitor its effectiveness through the annual Operational Practices Survey, or other appropriate means.

o. Emergency Operations

48. WECC has issued an Emergency Operations Procedure, which, among other things, defines the RC operator's role during emergency operations and in evaluating emergency conditions, including major system disturbances. The Procedure also provides specific guidance to RC operators on issuing "clear, concise and definitive" Reliability Coordinator Directives.

p. Modeling

49. WECC is developing the Base Case Coordination System (BCCS), to validate data automatically, build power flow base cases, and store dynamic data in a centralized, Web-accessible database. WECC is in the process of implementing the BCCS, and expects to fully implement the BCCS by June 30, 2016. WECC has offered training in the use of the BCCS to all TOPs in the Western Interconnection. If, despite its good faith and diligent efforts, WECC is unable to fully implement the BCCS due to irreconcilable technical issues or vendor performance, WECC, FERC and NERC staff shall confer and cooperate in order to reasonably address through other means any identified issues regarding validation of base case data or revision of power flow base cases.

[6] See paragraph 26 regarding the renegotiation of the UDSA, and interim measures to preserve data sharing.

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50. WECC and its Transmission Planners (TPs) have benchmarked their dynamic models against actual data from the September 8, 2011 event, as recommended by the Report. WECC worked with the TPs to identify modeling deficiencies and track improvements, and all modeling deficiencies identified as a result of the model validation process have been corrected.

51. WECC continues to reconcile its planning base cases to the Peak West-wide System Model used for operations, as recommended by the Report, and WECC and Peak continue to make any necessary changes in the two models.

52. WECC has added a generator tripping model to its base cases to provide an indication of when generators may trip during events.

53. WECC and Peak have conducted a two-phase study to identify facilities with at least one terminal below 100 kV that have an impact on the BES. In the first phase, WECC and Peak worked with TOPs to obtain a list of sub-100 kV facilities that the TOPs believed should be monitored due to potential loop flow, and performed a study using the Peak West-wide System Model. In the second phase, a study was conducted using WECC's planning model. WECC and Peak identified additional sub-100 kV facilities to be added to the Peak West-wide System Model and Peak's EMS model, and Peak is monitoring additional facilities identified by TOPs. Peak has alarmed all facilities identified through these studies in its EMS.

54. WECC will benchmark a base case, including dynamic models, on an annual basis, against actual system performance during the single most severe reportable disturbance that occurred on the Western Interconnection during the previous year. On a prospective basis, WECC will work with PCs and TPs to modify any discrepancies found between the base case (including dynamic models) and actual system performance.

q. **Voltage and Reactive Reserves**

55. WECC RC, and later Peak, implemented a voltage stability tool, the Region of Stability Excellence, or ROSE, which combines State Estimator and Phasor Measurement Unit (PMU) data for on-line calculation and visualization of the current operating point and its proximity to the voltage stability boundary, thus giving RC operators an improved awareness of system stability and potentially alerting them to impending system emergencies. Peak will fully implement ROSE by September 15, 2015. Peak will train all RC operators on ROSE.

D. Compliance Monitoring

56. WECC and Peak shall make semi-annual reports to Enforcement and NERC, which may be independent or joint reports, for one year after the Effective Date of this Agreement. Enforcement and NERC may require one additional year of semi-annual

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reporting if circumstances indicate the need for further monitoring. The first semi-annual report for each entity shall cover the first six-month period after the Effective Date of this Agreement and shall be submitted to Enforcement and NERC staff within thirty days thereafter. The subsequent report(s) shall be due in six month increments thereafter. Each report shall detail the following: (1) actions taken as of the date of the report to satisfy the terms of the Agreement, including all Reliability Enhancements and (2) actions taken to improve reliability and/or reliability compliance, including investments in new measures and training activities during the reporting period. Peak shall also detail any additional possible violations, compliance exceptions, or self-logged issues of Reliability Standards by Peak identified by Peak or WECC or reported to WECC, and whether and how Peak has addressed those matters. The reports must include affidavits executed by officers of WECC and Peak, respectively, that the compliance reports are true and accurate and must also include corroborative documentation or other satisfactory evidence demonstrating or otherwise supporting the content of these reports. Corroborative documentation shall include, at a minimum, the Operational Practices Survey results and a description of any actions planned in response to the Operational Practices Survey results, or, in the alternative, the results of other applicable monitoring and a description of any actions planned in response to those results. If, after WECC and/or Peak have fulfilled the semi-annual reporting requirement, either entity has not yet completed or implemented its mitigation or reliability activities, it shall continue to update Enforcement and NERC semi-annually on the progress and completion of the mitigation or reliability activities not yet completed or implemented. Updates shall include corroborative documentation or other satisfactory evidence of progress, completion or implementation.

VI. TERMS

57. The “Effective Date” of the Agreement shall be the date on which the Commission issues an order approving the Agreement without material modification. When effective, the Agreement shall resolve any and all reliability claims relating to the September 8 event within the jurisdiction of the Commission, and that occurred on or before the Effective Date, as to WECC, Peak or any affiliated entity.

58. Commission approval of the Agreement without material modification shall release WECC and Peak and forever bar the Commission and NERC from holding WECC or Peak, any affiliated entity, and any successor in interest to WECC or Peak liable for any and all claims within the jurisdiction of the Commission, arising out of any and all reliability matters related to the September 8 event or conduct addressed and stipulated to in this Agreement, that occurred on or before the Agreement’s Effective Date.

59. Failure to make timely civil penalty payments or to comply with the Reliability Enhancements, mitigation and reliability activities, and monitoring agreed to herein, or

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any other provision of the Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act (FPA), 16 U.S.C. §792, *et seq.*, and may subject WECC to additional action under the enforcement provisions of the FPA.

60. Failure to comply with the Reliability Enhancements, mitigation and reliability activities, and monitoring agreed to herein, or any other provision of the Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act (FPA), 16 U.S.C. §792, *et seq.*, and may subject Peak to additional action under the enforcement provisions of the FPA.

61. If WECC does not make any portion of the civil penalty payment described above at the time(s) agreed by the parties, interest payable to the United States Treasury and NERC shall begin to accrue pursuant to the Commission's regulations at 18 C.F.R. § 35.19(a) (2) (iii) (2014) from the date that payment is due.

62. The Agreement binds WECC, Peak, and their agents, successors, and assignees. The Agreement does not create any additional or independent obligations on WECC or Peak, or any affiliated entity, its agents, officers, directors, or employees, other than the obligations identified in the Agreement.

63. The findings of violations detailed in the Agreement shall constitute prior violations for consideration in any future Commission or NERC enforcement proceeding against Peak or any successor.

64. The signatories to the Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer or promise of any kind by any member, employee, officer, director, agent or representative of Enforcement, NERC, WECC or Peak has been made to induce the signatories or any other party to enter into the Agreement.

65. Unless the Commission issues an order approving the Agreement in its entirety and without material modification, the Agreement shall be null and void and of no effect whatsoever, and Enforcement, NERC, WECC, and Peak shall not be bound by any provision or term of the Agreement, unless otherwise agreed to in writing by Enforcement, NERC, WECC and Peak.

66. WECC and Peak agree that the Commission's order approving the Agreement without material modification shall be a final and unappealable order assessing a civil penalty under the Federal Power Act. WECC and Peak waive findings of fact and conclusions of law, rehearing of any Commission order approving the Agreement without material modification, and judicial review by any court of any Commission order approving the Agreement without material modification.

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67. The Agreement can be modified only if in writing and signed by Enforcement, NERC, WECC and Peak, and any modifications will not be effective unless approved by the Commission.

68. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity and accepts the Agreement on the entity's behalf.

69. The undersigned representatives of WECC and Peak affirm that he or she has read the Agreement, that all of the matters set forth in the Agreement are true and correct to the best of his or her knowledge, information and belief, and that he or she understands that the Agreement is entered into by Enforcement and NERC in express reliance on those representations.

70. The Agreement may be signed in counterparts.

71. The Agreement is executed in quadruplicate, each of which so executed shall be deemed to be an original.

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Agreed to and accepted:

Larry Parkinson
Director, Office of Enforcement
Federal Energy Regulatory Commission

Date: 5/7/15

Charles A. Berardesco
Senior Vice President, General Counsel and Corporate Secretary
North American Electric Reliability Corporation

Date: 5/14/15

James B. Robb
Chief Executive Officer
Western Electricity Coordinating Council

Date: 6 MAY 2015

Gary Stephenson
President and Chief Executive Officer
Peak Reliability

Date: MAY 12, 2015

Document Content(s)

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151 FERC ¶ 61,129
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RD14-14-000

ORDER APPROVING RELIABILITY STANDARD

(Issued May 13, 2015)

1. On September 15, 2014, the North American Electric Reliability Corporation (NERC) submitted a petition seeking approval of a modified Protection and Control (PRC) Reliability Standard PRC-004-3 (Protection System Misoperation Identification and Correction), pursuant to section 215(d) of the Federal Power Act (FPA).[1] The modified Reliability Standard requires transmission owners, generator owners, and distribution providers to identify and correct causes of misoperations[2] of certain protection systems.[3] NERC also requests approval of two new defined terms to include in the NERC Glossary of Terms Used in NERC Reliability Standards (NERC Glossary). Finally, NERC requests approval of the implementation plan for Reliability Standard PRC-004-3, as well as approval of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs).

2. As explained below, the Commission finds that revised Reliability Standard PRC-004-3, including the associated new Glossary terms and implementation plan, is just, reasonable, not unduly discriminatory or preferential and in the public interest. The Commission also approves the VSLs associated with the Reliability Standard, as

[1] 16 U.S.C. § 824o(d) (2012).

[2] The NERC Glossary defines "Misoperation" as "[t]he failure of a Composite Protection System to operate as intended for protection purposes. …"

[3] The NERC Glossary defines "Protection System" as "[p]rotective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions. …"

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proposed by NERC. The Commission, however, directs NERC to submit a compliance filing, within 60 days of the issuance of this order, to address certain concerns regarding the VRF designations for Requirements R1 through R6, as described below.

I. Background

3. The Commission certified NERC as the Electric Reliability Organization (ERO), as defined in section 215 of the FPA, in July 2006.[4] In Order No. 693, the Commission approved 83 of 107 proposed Reliability Standards submitted by NERC, including approval of PRC-004-1 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations).[5] In addition, the Commission directed that NERC (1) consider a commenter's suggestion regarding whether PRC-004-1 should apply to load serving entities and transmission operators; and (2) clarify what entity should develop the procedures for corrective action plans.[6]

4. Subsequently, NERC submitted, and the Commission approved, Reliability Standard PRC-004-2, which included modifications in response to the Commission's directives in Order No. 693.[7]

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[4] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g* 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[5] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1467, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[6] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1469.

[7] *North American Electric Reliability Corp.*, 134 FERC ¶ 61,015 (2011). The Commission has also approved minor revisions to the standard, as well as an interpretation. *See Generator Requirements at the Transmission Interface*, Order No. 785, 144 FERC ¶ 61,221 (2012) (approving PRC-004-2.1a and clarifying that the requirements in PRC-004 extend not only to protection systems associated with the generating facility or station, but also to protection systems associated with the generator interconnection facilities); *North American Electric Reliability Corp.*, 136 FERC ¶ 61,208 (2011) (approving an interpretation for the term "transmission Protection System" as it appears in Requirements R1 and R3).

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5. In Order No. 693, the Commission neither accepted nor remanded Reliability Standard PRC-003-1 (Regional Procedures for Analysis of Misoperations of Transmission and Generation Protection System). The Commission identified the standard as a "fill-in-the-blank" standard and noted that the associated regional procedures had not been submitted. Concluding that additional information was needed regarding the regional procedures, the Commission directed NERC to consider whether greater consistency can be achieved "on an Interconnection-wide basis" in Reliability Standard PRC-003-1.[8]

II. NERC's Petition

6. In its Petition, NERC explains that Reliability Standard PRC-004-3 was developed "as a means to address the reliability risks posed by misoperations."[9] According to NERC, the modified Reliability Standard, which replaces Reliability Standards PRC-004-2.1a and PRC-003-1, requires transmission owners, generator owners, and distribution providers to identify and correct causes of misoperations of certain protection systems. Noting that nearly all major system failures that are not related to severe weather include misoperations as a contributing factor, NERC states that PRC-004-3, in concert with a Section 1600 Misoperations Data Request, provides the means to address protection system misoperations. Specifically, NERC states "reducing the risk to reliability from Protection System misoperations will require consistent collection of Misoperation information along with systematic analysis and correction of the underlying causes of preventable Misoperations. Proposed PRC-004-3, and the parallel Section 1600 Data Request provide means to accomplish this systematic analysis and correction."[10]

7. Reliability Standard PRC-004-3, which applies to transmission owners, generator owners, and distribution providers, contains six requirements. Requirement R1 obligates an applicable entity "that owns a BES [bulk electric system] interrupting device that operated under [specified circumstances] shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation."[11] Pursuant to Requirement R2, an applicable entity must notify other protection system owners of a misoperation. Under Requirement R3, an entity that

[8] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1461.

[9] NERC Petition at 9.

[10] *Id.*

[11] *Id.* at 15.

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owns a portion of a composite protection system[12] and receives notice under Requirement R2 has the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation to determine whether its protection system components caused a misoperation.

8. Requirement R4 requires an entity that owns a "BES interrupting device" to "perform investigative action(s)" to determine the cause or causes of an identified misoperation. NERC explains that an entity must perform at least one investigative action every two full calendar quarters until the investigation is complete. According to NERC, an investigation is considered complete when an entity identifies the cause of a misoperation or declares that no cause was determined.[13] Under Requirement R5, an applicable entity must, within 60 calendar days of identifying a cause of a misoperation, develop a corrective action plan to address the cause of the misoperation and to evaluate its applicability to the entity's protection systems installed in other locations, or explain why corrective actions are beyond the entity's control or would not improve bulk electric system reliability.[14] Finally, Requirement R6 requires entities to "implement" a corrective action plan developed under Requirement R5.

9. NERC explains that PRC-004-3 "eliminates the need for regional procedures by providing continent-wide parameters for investigating Protection System operations and identifying Misoperations," thereby addressing the Commission's concerns with consistency reflected in the Order No. 693 discussion of Reliability Standard PRC-003-1. In addition, NERC notes that proposed Reliability Standard PRC-004-3 applies to underfrequency load shedding "that is intended to trip one or more Bulk Electric System Elements" in order to close a reliability gap where misoperations of such relays were not previously addressed by a reliability standard.[15]

10. NERC states that the standard drafting team addressed the Commission's directive to consider whether to include load serving entities and transmission operators in the applicability section for Reliability Standard PRC-004-3. According to NERC, the standard drafting team concluded that "the proper functional entities to include in the

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[12] NERC proposes to define a composite protection system as "[t]he total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded."

[13] NERC Petition at 20.

[14] *Id.* at 21.

[15] *Id.* at 10.

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applicability [for Reliability Standard PRC-004-3] are the Transmission Owner, Generator Owner, and Distribution Provider who own the BES Protection Systems."[16] NERC explains that owners of protection systems have the personnel with subject matter expertise, design and setting information, and disturbance data necessary to assess protection system misoperations and, therefore, it is appropriate for the owner to have "the responsibility to assure proper operation and implement corrective actions as needed."[17]

11. NERC also requests approval of the proposed definitions of the terms "Composite Protection System" and "Misoperation." Finally, NERC proposes an implementation plan that includes an effective date for the revised Reliability Standard and definitions that is the first day of the first calendar quarter that is twelve months after the date that the Commission approves the standard. Concurrent with the effective date, the implementation plan calls for the retirement of currently-effective Reliability Standard PRC-004-2.1a and "pending" standard PRC-003-1.[18]

III. Notice of Filing and Responsive Pleading

12. Notice of NERC's Petition was issued on September 18, 2014 and published on September 30, 2014 in the *Federal Register*, with comments, protests and motions to intervene due on or before October 20, 2014.[19] Dominion Resources Services, Inc. (Dominion) filed a timely motion to intervene.

IV. Discussion

13. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2014), the timely motion to intervene filed by Dominion serves to make it a party to this proceeding.

A. Reliability Standard PRC-004-3

14. We approve Reliability Standard PRC-004-3 and find that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[16] *Id.* at 24.

[17] *Id.*

[18] *Id.* at Ex. B.

[19] 79 Fed. Reg. 58,760 (2014).

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Reliability Standard PRC-004-3 requires transmission owners, generator owners, and distribution providers to identify and correct causes of misoperations of certain protection systems. We agree with NERC that the modified Reliability Standard clarifies the process and establishes timeframes that registered entities must follow in analyzing and correcting protection system misoperations. In addition, the process in the revised Reliability Standard allows the entities to declare if the cause of the misoperation could not be identified, and the timeframes allow the entities to investigate and correct the causes of the misoperations within a reasonable period of time. These improvements to the Reliability Standard should benefit reliability by providing clear expectations on how applicable entities should investigate, communicate about and mitigate specified misoperations.

15. Further, we agree with NERC that Reliability Standard PRC-004-3 addresses an existing reliability gap by applying the standard to underfrequency load shedding that is intended to trip one or more bulk electric system elements. This improvement to the scope of the standard requires that the analysis of misoperations that may be associated with underfrequency load shedding facilities is performed. Finally, we determine that PRC-004-3 adequately addresses the relevant directives in Order No. 693 by providing a consistent, continent-wide approach to addressing misoperations. Likewise, as directed in Order No. 693, the NERC drafting team considered whether to expand the applicability of the standard and provided a reasonable explanation for the decision not to expand the applicability.

16. In addition, we approve: (1) NERC's implementation plan for Reliability Standard PRC-004-3, which includes retiring Reliability Standards PRC-004-2.1a and PRC-003-1 when PRC-004-3 becomes effective;[20] (2) the addition of the terms "Composite Protection System" and "Misoperation" to the NERC Glossary; and (3) the proposed VSLs designations for Reliability Standard PRC-004-3. Below, we discuss certain concerns with the assigned VRFs for PRC-004-3.

[20] As noted above, the Commission in Order No. 693 did not approve proposed Reliability Standard PRC-003-1 but, rather, pended the standard based on the need for additional information. With our approval of PRC-004-3, Reliability Standard PRC-003-1 will be considered "retired" and no longer pending before the Commission.

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B. Violation Risk Factors

17. On May 18, 2007, the Commission established guidelines for determining whether to approve VRFs proposed by NERC.[21] We conclude that the "medium" VRFs assigned to Requirements R1 through R6 of PRC-004-3 are not consistent with the Commission's guidelines. Nor are the VRF assignments in alignment with NERC's definitions of high, medium and low VRF levels. Specifically, NERC has not adequately justified the proposed "medium" VRF designations considering : (1) the important reliability objectives of the underlying Reliability Standard; and (2) the "high" risk designations for the corresponding Requirements of the currently-effective standard PRC-004-2.1a. Accordingly, we direct NERC to revise the VRF designations to address our concerns discussed below.

18. NERC states that the six discrete requirements of proposed Reliability Standard PRC-004-3 "incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1."[22] NERC states further that:

> The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium

[21] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, *order on reh'g*, 120 FERC ¶ 61,145 (2007); *North American Electric Reliability Corp.*, 123 FERC ¶ 61,284, at PP 20-35, *order on reh'g & compliance*, 125 FERC ¶ 61,212 (2008); *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

[22] NERC Petition, Ex. F (Analysis of Violation Risk Factors and Violation Severity Levels) at 4.

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> VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.[23]

19. The Commission is not persuaded by NERC's explanation. Reliability Standard PRC-004-2.1a, Requirements R1 and R2, which apply to Protection Systems, are assigned a High VRF. In contrast, Reliability Standards PRC-016-0.1 and PRC-022-1 apply to Remedial Action Schemes and to Under-Voltage Load Shedding Program Performance and not Protection Systems. Regional Standard PRC-004-WECC-1, Requirement R1 applies to the analysis of both Remedial Action Schemes and Protection Systems, while all four provisions of Requirement R2, which require actions to protect the Bulk-Power System from a Protection System or Remedial Action Schemes misoperation, are assigned a High VRF. Thus, while it is true, as NERC claims, that there is not a one-to-one correlation between the currently-effective and proposed PRC-004 requirements, it is clear that the provisions of the currently-effective standards that pertain to protection system performance are assigned "high" VRF levels.

20. Moreover, Commission VRF Guideline 4 calls for consistency between the assignment of a particular VRF and NERC's definition of that VRF level.[24] The Commission-approved NERC VRF definition for "high" VRF states, in pertinent part, that a requirement should have a "high" VRF designation if a violation of the requirement "could place the bulk electric system at an unacceptable risk of instability, separation or cascading failures." NERC has designated protection system misoperations as one of the top priority reliability risks, noting that unnecessary trips resulting from misoperations can lead to cascading failures.[25] In contrast, the Commission-approved NERC VRF definition for "medium" provides that the violation of the underlying requirement could not result in, among other things, a cascading sequence of failures or place the bulk electric system at an unacceptable risk of, among other things, cascading failures. We are not persuaded by NERC's technical justification for lowering the subject VRF assignments to "medium," particularly in light of NERC's findings that misoperations

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[23] *Id.*, Ex. F at 5.

[24] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145 at PP 28-31.

[25] *See* "ERO Top Priority Reliability Risks 2014-2017," January 16, 2014, http://www.nerc.com/comm/RISC/Agenda%20Highlights%20and%20Minutes/ERO%20Top%20Priority%20Reliability%20Risks%202014.pdf at 12; *see also* NERC "State of Reliability Report," May 2014 at Page 17.

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can lead to cascading outages.[26] For the reasons stated above, we direct NERC to submit a compliance filing within 60 days of issuance of this order that revises the proposed "medium" VRF designations to "high."

V. Information Collection Statement

21. The information collection requirements contained in this order are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[27] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[28] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the reporting requirements of this order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. Under the Paperwork Reduction Act, the Commission solicits comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Comments are due within 60 days from publication in the Federal Register.

22. Public Reporting Burden: Reliability Standard PRC-004-3 requires each transmission owner, generator owner, and distribution provider to provide notification of BES interrupting devices that operated in accordance with the Requirement R2.[29] Our estimate below regarding the number of respondents is based on the NERC Compliance Registry as of January 30, 2015. According to the NERC Compliance Registry, NERC has registered in the United States 326 transmission owners (TO), 914 generator owners (GO), and 471 distribution providers (DP). However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers

[26] *Id.*

[27] 44 U.S.C. 3507(d) (2012).

[28] 5 CFR 1320.11 (2014).

[29] Requirement R2 provides "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2."

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incorporate some double counting. The total number of unique entities that may be identified as a notification provider (e.g. applicable entity) in accordance with Reliability Standard PRC-004-3 will be approximately 659 entities registered in the United States as a transmission owner, generator owner, and/or distribution provider.

FERC-725G1[30]						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response**[31] **(4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
Notifications to TO/GO/DP per Requirement R2	659	1	659	8 $584	5,272 $384,856	$584
One-time review and adjustment of existing program	659	1	659	2 $146	1,318 $96,214	$146
Evidence Retention	659	1	659	12 $384	7,908 $253,056	$384
TOTAL					14,498 $734,126	$1,114

[30] FERC-725G is a currently pending request at OMB. Only one submittal can be pending OMB review under each control number, therefore, FERC-725G1 will be used for timely submittal.

[31] The estimates for cost per response are derived using the following formula: Average Burden Hours per Response * $n per Hour = Average Cost per Response. The $73 hourly cost figure is the average of the salary plus benefits for a manager and an engineer (rounded to the nearest dollar); $32/hour is the salary plus benefits for information and record clerks. The figures are taken from the Bureau of Labor Statistics at http://bls.gov/oes/current/naics3_221000.htm.

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NERC states that "moving the periodic reporting of Misoperations from the standard (PRC-004-2.1) and into a separate data request pursuant to Section 1600 of NERC's Rules of Procedure will permit NERC's data analysis to continue separately from compliance with the standard and continue reporting, using a standardized template, for all entities subject to the data request."[32] Therefore, registered entities will still conduct the collection. The burden associated with PRC-004-2.1 will be removed from FERC-725A (1902-0244) and added to FERC-725, as reflected in the table below.

Documentation of Misoperations Analyses and Corrective Action Plans Per PRC-004-2.1						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[33] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
FERC-725	659	1	659	96 $7,008	63,264 $4,618,272	$7,008
FERC-725A	-659	-1	-659	-96 -$7,008	-63,264 - $4,618,272	-$7,008
Total Net Change	0	0	0	0	0	0

Title: Certification of the Electric Reliability Organization and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards; Mandatory Reliability Standards for the Bulk-Power System: Reliability Standard PRC-004-3

Action: Proposed revisions FERC-725; proposed new collection FERC-725G1
OMB Control No: FERC-725 (1902-0269), FERC-725G1 (OMB Control No to be determined)

[32] NERC Petition at 23.

[33] The estimates for cost per response are derived using the following formula: Average Burden Hours per Response * $n per Hour = Average Cost per Response. The $73 hourly cost figure is the average of the salary plus benefits for a manager and an engineer (rounded to the nearest dollar); $32/hour is the salary plus benefits for information and record clerks. The figures are taken from the Bureau of Labor Statistics at http://bls.gov/oes/current/naics3_221000.htm.

20150513-3069 FERC PDF (Unofficial) 05/13/2015

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: Occasional.

Necessity of the Information: Reliability Standard PRC-004-3 provides improvements over the currently-effective PRC-004-2.1a, including clearer requirements that establish what is required of the applicable entities and timeframes for the reliability objectives to be completed.

23. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873].

VI. Effective Date

24. This order will become effective upon issuance.

The Commission orders:

(A) Reliability Standard PRC-004-3 is hereby approved as just, reasonable, not unduly discriminatory, and in the public interest, as discussed in the body of this order.

(B) The revisions to NERC's Glossary of Terms, the proposed implementation plan and the proposed Violation Severity Levels for Reliability Standard PRC-004-3 are hereby approved, as discussed in the body of this order.

(C) NERC is hereby directed to submit a compliance filing within 60 days of this order addressing the proposed Violation Risk Factors, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

RD14-14-000.DOCX.....1-12

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Technical Conference Docket No. AD15-7-000

SUPPLEMENTAL NOTICE WITH AGENDA

(April 28, 2015)

As announced in the Notice of Technical Conference issued on April 9, 2014, the Commission will hold a technical conference on Thursday, June 4, 2015 from 10:00 a.m. to 4:00 p.m. to discuss policy issues related to the reliability of the Bulk-Power System. The agenda for this conference is attached. Commission members will participate in this conference.

Registration is not required, but is encouraged. Attendees may register at: https://www.ferc.gov/whats-new/registration/06-04-15-form.asp.

After the close of the conference, the Commission will accept written comments regarding the matters discussed at the technical conference. Any person or entity wishing to submit written comments regarding the matters discussed at the conference should submit such comments in Docket No. AD15-7-000 on or before July 9, 2014.

Information on this event will be posted on the Calendar of Events on the Commission's web site, www.ferc.gov, prior to the event. The conference will be transcribed. Transcripts will be available for a fee from Ace Reporting Company (202-347-3700). A free webcast of this event is also available through www.ferc.gov. Anyone with Internet access who desires to listen to this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to the webcast. The Capitol Connection provides technical support for webcasts and offers the option of listening to the meeting via phone-bridge for a fee. If you have any questions, visit www.CapitolConnection.org or call 703-993-3100.

Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to accessibility@ferc.gov or call toll free 1-866-208-3372 (voice) or 202-502-8659 (TTY), or send a FAX to 202-208-2106 with the required accommodations.

For more information about this conference, please contact:

Sarah McKinley
Office of External Affairs
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426
(202) 502-8368
sarah.mckinley@ferc.gov

Kimberly D. Bose,
Secretary.

Commissioner-Led Reliability Technical Conference

Docket No. AD15-7-000
Thursday, June 4, 2015
10:00 a.m. – 4:00 p.m.

10:00 a.m. Commissioners' Opening Remarks

10:15 a.m. Introductions:

10:30 a.m. Panel I: 2015 State of Reliability Report

Presentations: The North American Electric Reliability Corporation (NERC) recently released its 2015 State of Reliability report, which highlights reliability performance, current trends and challenges, and recommendations for maintaining and improving the reliability of the bulk power system. Panelists will be asked to address the following issues:

a. What does the 2015 report show about the effectiveness of NERC's reliability activities and related industry efforts? What progress has been made with respect to the recommendations in the 2014 report and what are the obstacles to continued progress? What priorities have been identified in the 2015 State of Reliability report and how are these different from the 2014 report? Does the 2015 report indicate that more resources should be directed to particular reliability risks or areas?

b. Protection system misoperation and AC substation equipment failures are again identified as major risk areas that are major contributors to system disturbances. In December 2014, NERC staff released an analysis of system protection misoperations.[1] What were the key findings and what steps, if any, should be taken to decrease the number of misoperations, and are there any obstacles that exist to reducing this number? What is the status of NERC's AC Substation Equipment Task Force[2] and what

[1] NERC Staff Analysis of System Protection Misoperations, December 2014
[2] http://www.nerc.com/comm/PC/Pages/AC-Substation-Equipment-Task-Force-(ACSETF).aspx

considerations have been given to reducing AC substation equipment failure?

c. The report indicates that the number of non-weather-related load loss events and the MW load loss amount for the past three years is significantly less than previous years. What are the key factors in continuing this trend?

d. Are there other significant issues that require analysis or changes in the planning and operation of the bulk power system during the next 1-5 years?

Panelists: TBD

12:00 a.m. Lunch

1:00 p.m. Panel II: Emerging Issues

Presentations: Significant changes to our Nation's fuel sources and power supply portfolio could result from such factors as the affordability of domestic natural gas, Federal and state policies on renewable and other resources, and new environmental regulations. Panelists will be asked to address the following issues:

a. What emerging issues are going to challenge NERC and industry? How are these issues being considered in long-term, seasonal and operational planning studies?

b. What progress has been made by NERC's Essential Reliability Services Task Force in developing new approaches to the "reliability building blocks" (voltage support, ramping capability, and frequency support) needed for reliability and for ensuring their provision as the resource mix changes? Are any changes in reliability standards or other regulatory requirements needed or appropriate?

c. What approaches are being developed to address recent declines in reserve margins in several regions as described in the 2014 NERC Long Term Reliability Assessment report? What connection, if any, does this trend have with resource mix changes? Should reserve margin targets be altered or rethought as the overall resource mix changes?

d. Are additional efforts needed to maintain reliability as the growth of natural gas-fired generation continues? What specific additional improvements still need to be made?

e. In March of this year, the Commission completed a series of conferences on EPA's proposed Clean Power Plan. Since that time, is there new or updated information that warrants consideration on this issue?

Panelists: TBD

2:15 p.m. Break

2:30 p.m. Panel III: ERO Performance and Initiatives

Presentations: As the ERO, NERC identifies various evolving issues that face the bulk power system and develops initiatives to address those issues. Panelists will be asked to address the following issues:

a. What are the initial results of the risk-based Compliance Monitoring and Enforcement Program? What specific improvements to reliability performance, reduction to reliability risks, and increased compliance efficiencies are NERC and the industry experiencing as a result of this initiative?

b. Explain the feedback loop from event analysis and compliance monitoring and enforcement to standards development. What are some examples of how standards were modified or developed as a result of bulk-power system events?

c. Are the ESCC and ES-ISAC working well in enhancing security? Would you suggest any changes in how they function?

d. NERC filed its Stage 2 proposal on geomagnetic disturbances early this year. Has any significant new information or analysis been published or issued since then? Similarly, how is work progressing on industry's implementation of the physical security standard and version 5 of the cyber security standards?

Panelists: TBD

3:45 p.m. Commissioners' Closing Remarks

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Technical Conference	Docket Nos. AD15-7-000
North American Electric Reliability Corporation	RR15-2-000

SUPPLEMENTAL NOTICE WITH FINAL AGENDA

(May 28, 2015)

As announced in the Notice of Technical Conference issued on April 9, 2015, the Commission will hold a technical conference on Thursday, June 4, 2015 from 10:00 a.m. to 4:00 p.m. to discuss policy issues related to the reliability of the Bulk-Power System. The agenda for this conference, with panelists, is attached. Commission members will participate in this conference.

Registration is not required, but is encouraged. Attendees may register at: https://www.ferc.gov/whats-new/registration/06-04-15-form.asp

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Kimberly D. Bose,
Secretary.

Commissioner-Led Reliability Technical Conference

Docket Nos. AD15-7-000 and RR15-2-000

Thursday, June 4, 2015
10:00 a.m. – 4:00 p.m.

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[1] NERC Staff Analysis of System Protection Misoperations, December 2014

status of NERC's AC Substation Equipment Task Force[2] and what considerations have been given to reducing AC substation equipment failure?

c. The report indicates that the number of non-weather-related load loss events and the MW load loss amount for the past three years is significantly less than previous years. What are the key factors in continuing this trend?

d. Are there other significant issues that require analysis or changes in the planning and operation of the bulk power system during the next 1-5 years?

Panelists:
Gerry W. Cauley, North American Electric Reliability Corporation
Tom Burgess, North American Electric Reliability Corporation
Vice Chairman Asim Haque, Public Utilities Commission of Ohio
Peter Fraser, Ontario Energy Board
Prof. Massoud Amin, Chairman, Board of Directors, Texas Reliability Entity
Prof. Ian Dobson, Iowa State University
Allen Mosher, American Public Power Association
David Boguslawski, Eversource Energy

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[2] http://www.nerc.com/comm/PC/Pages/AC-Substation-Equipment-Task-Force-(ACSETF).aspx

mix changes? Should reserve margin targets be altered or rethought as the overall resource mix changes?

d. Are additional efforts needed to maintain reliability as the growth of natural gas-fired generation continues? What specific additional improvements still need to be made?

e. In March of this year, the Commission completed a series of conferences on EPA's proposed Clean Power Plan. Since that time, is there new or updated information that warrants consideration on this issue?

Panelists:
Mark Lauby, North American Electric Reliability Corporation
John Moura, North American Electric Reliability Corporation
Peter Brandien, ISO New England
Thomas J. Galloway, North American Transmission Forum
Prof. Anjan Bose, Washington State University
David T. Zwergel, Midcontinent Independent System Operator, Inc.
Mark Rothleder, California Independent System Operation Corporation
Warren Lasher, Electric Reliability Council of Texas
John E. Shelk, Electric Power Supply Association

2:15 p.m. Break

2:30 p.m. Panel III: ERO Performance and Initiatives

Presentations: As the ERO, NERC identifies various evolving issues that face the bulk power system and develops initiatives to address those issues. Panelists will be asked to address the following issues:

a. What are the initial results of the risk-based Compliance Monitoring and Enforcement Program? What specific improvements to reliability performance, reduction to reliability risks, and increased compliance efficiencies are NERC and the industry experiencing as a result of this initiative?

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d. NERC filed its Stage 2 proposal on geomagnetic disturbances early this year. Has any significant new information or analysis been published or issued since

then? Similarly, how is work progressing on industry's implementation of the physical security standard and version 5 of the cyber security standards?

Panelists:

Gerry W. Cauley, North American Electric Reliability Corporation
Sonia Mendonca, North American Electric Reliability Corporation
Dr. David Ortiz, U.S. Department of Energy
Scott Henry, SERC Reliability Corporation
Angela Sheffield, Georgia Transmission Corp.
Sylvain Clermont, Hydro-Québec TransÉnergie, on behalf of the Canadian Electricity Association
Steve Wright, Chelan Public Utility District
William J. Gallagher, The Transmission Access Policy Study Group
Jeffery Gust, MidAmerican Energy on behalf of Berkshire Hathaway Energy

3:45 p.m. Commissioners' Closing Remarks

151 FERC ¶ 61,026
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-9-000]

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard

(Issued April 16, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: Pursuant to the Federal Power Act, the Commission proposes to approve a revised Reliability Standard, PRC-005-4 (Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance), developed and submitted by the North American Electric Reliability Corporation (NERC). In addition, the Commission proposes to approve one new definition and four revised definitions referenced in the proposed Reliability Standard, as well as NERC's proposed violation risk factors, violation severity levels, and implementation plan. Consistent with Order No. 758, the proposed Reliability Standard requires applicable entities to test and maintain certain sudden pressure relays as part of a protection system maintenance program.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

Tom Bradish (Technical Information)
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Federal Energy Regulatory Commission
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Julie Greenisen (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6362
julie.greenisen@ferc.gov

SUPPLEMENTARY INFORMATION:

151 FERC ¶ 61,026
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard	Docket No. RM15-9-000

NOTICE OF PROPOSED RULEMAKING

(Issued April 16, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve a revised Reliability Standard, PRC-005-4 (Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance), developed and submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). In addition, the Commission proposes to approve one new definition and four revised definitions referenced in the proposed Reliability Standard, as well as NERC's proposed violation risk factors, violation severity levels, and implementation plan. Consistent with Order No. 758,[2] the proposed Reliability Standard requires applicable entities to test and maintain certain sudden pressure relays as part of a protection system maintenance program.

[1] 16 U.S.C. 824o (2012).

[2] *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094, *clarification denied*, 139 FERC ¶ 61,227 (2012).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

May 7, 2015

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	May 14, 2015 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1016TH - MEETING

REGULAR MEETING

May 14, 2015

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD02-1-000	Agency Business Matters
A-2	AD02-7-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD06-3-000	Market Update
		ELECTRIC
E-1	RM15-11-000	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events
E-2	ER13-1957-000	ISO New England Inc. New York Independent System Operator, Inc. PJM Interconnection, L.L.C.
	ER13-1942-000 ER13-1946-000	New York Independent System Operator, Inc.
	ER13-1960-000	ISO New England Inc. New England Power Pool Participants Committee
	ER13-1947-000	PJM Interconnection, L.L.C.
	ER13-1926-000	PJM Interconnection, L.L.C. Duquesne Light Company
	(not consolidated)	
E-3	ER13-75-006 ER13-75-007 ER13-75-008 ER15-416-000	Public Service Company of Colorado
	ER13-77-004 ER13-77-005 ER13-77-006 ER15-433-000	Tucson Electric Power Company
	ER13-78-004 ER13-78-005 ER13-78-006 ER15-434-000	UNS Electric, Inc.
	ER13-79-004	Public Service Company of New Mexico

	ER13-79-005	
	ER13-79-006	
	ER15-413-000	
	ER13-82-004	Arizona Public Service Company
	ER13-82-005	
	ER13-82-006	
	ER15-411-000	
	ER13-91-004	El Paso Electric Company
	ER13-91-005	
	ER15-426-000	
	ER13-96-004	Black Hills Power, Inc.
	ER13-96-005	
	ER15-431-000	
	ER13-97-004	Black Hills Colorado Electric Utility Company, LP
	ER13-97-005	
	ER15-430-000	
	ER13-105-004	NV Energy, Inc.
	ER15-423-000	
	ER15-424-000	
	ER15-428-000	
	ER15-428-001	
	ER13-120-004	Cheyenne Light, Fuel, & Power Company
	ER13-120-005	
	ER15-432-000	
E-4	ER13-94-004	Avista Corporation
	ER15-422-000	
	ER13-99-003	Puget Sound Energy, Inc.
	ER15-429-000	
	ER13-836-003	MATL LLP
E-5	EL13-33-001 EL13-33-003	ENE (Environment Northeast); The Greater Boston Real Estate Board; and National Consumer Law Center v. Bangor Hydro-Electric Company; Central Maine Power Company; New England Power Company; New Hampshire Transmission LLC; NSTAR Electric Company; Northeast Utilities Service Company; The United Illuminating Company; Unitil Energy Systems, Inc.; Fitchburg Gas and Electric Light Company; and Vermont Transco, LLC
	EL14-86-001	Attorney General of the Commonwealth of Massachusetts; Connecticut Public Utilities Regulatory Authority; Massachusetts Municipal Wholesale Electric Company; New Hampshire Electric Cooperative, Inc.; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; George Jepsen, Attorney General of the State of Connecticut; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; New Hampshire Office of the Consumer Advocate; Rhode Island Division of Public Utilities Carriers; Vermont Department of Public Service; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; Western Massachusetts Industrial Group; Environment Northeast; National Consumer Law Center; Greater Boston Real Estate Board; and

		Industrial Energy Consumer Group v. Bangor Hydro-Electric Company; Central Maine Power Company; New England Power Company; New Hampshire Transmission LLC; The Connecticut Light and Power Company; Western Massachusetts Electric Company; Public Service Company of New Hampshire; NSTAR Electric Company; The United Illuminating Company; Unitil Energy Systems, Inc.; Fitchburg Gas and Electric Light Company; and Vermont Transco, LLC
E-6	EL13-78-001 EL12-59-001	Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Company
E-7	ER15-1196-000 ER15-1196-001	Nevada Power Company
E-8	QM15-2-000	Northern States Power Company, a Minnesota corporation
E-9	EC15-76-000	PowerMinn 9090, LLC Fibrominn, LLC Benson Power, LLC CPV Biomass Holdings, LLC
E-10	ES15-14-000	NorthWestern Corporation
E-11	OMITTED	
E-12	ER07-956-008	Entergy Services, Inc.
E-13	ER10-3357-000 ER10-3357-001	Entergy Services, Inc.
E-14	EL15-19-000	Avista Corporation
E-15	ER15-990-000	Southwest Power Pool, Inc.

GAS

G-1	RP13-436-001	CAlifornians for Renewable Energy, Inc. Michael E. Boyd Robert M. Sarvey v. Pacific Gas and Electric Company

HYDRO

H-1	OMITTED	
H-2	P-2169-109	Brookfield Smoky Mountain Hydropower, LLC
H-3	RM15-18-000	Commencement of Assessment of Annual Charges

H-4	P-1892-027 P-1855-046 P-1904-074	TransCanada Hydro Northeast Inc.

CERTIFICATES

C-1	CP14-513-000	Impulsora Pipeline, LLC
C-2	CP14-509-000	Paiute Pipeline Company
C-3	CP14-522-000	Algonquin Gas Transmission, LLC
C-4	OMITTED	
C-5	CP15-161-000	Roadrunner Gas Transmission, LLC
C-6	CP15-32-000 CP15-33-000	Black Hills Shoshone Pipeline, LLC Energy West Development, Inc.

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

June 11, 2015

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	June 18, 2015 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1017TH - MEETING

REGULAR MEETING

June 18, 2015

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD02-1-000	Agency Business Matters
A-2	AD02-7-000	Customer Matters, Reliability, Security and Market Operations
		ELECTRIC
E-1	ER14-2464-002 EL15-36-000	Midcontinent Independent System Operator, Inc. Otter Tail Power Company v. Midcontinent Independent System Operator, Inc.
E-2	RM15-16-000	Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards
E-3	RM15-7-000 RM15-12-000 RM15-13-000	Revisions to Emergency Operations Reliability Standards Revisions to Undervoltage Load Shedding Reliability Standards Revisions to the Definition of “Remedial Action Scheme” and Related Reliability Standards
E-4	RM15-5-000	Revised Exhibit Submission Requirements for Commission Hearings
E-5	RR15-8-000	North American Electric Reliability Corporation
E-6	ER12-1338-001 ER12-1347-002	Duke Energy Corporation and Progress Energy, Inc. Carolina Power & Light Co.
E-7	ER15-3-001	PJM Interconnection, L.L.C. and Commonwealth Edison Company

E-8	ER15-1137-000	ISO New England Inc.
E-9	ER14-781-002 ER14-781-003	Southwest Power Pool, Inc.
E-10	EL15-61-000	Benjamin Riggs v. Rhode Island Public Utilities Commission
E-11	EL14-46-000	Ameren Services Company
E-12	EL15-18-000	Consolidated Edison Company of New York, Inc. v. PJM Interconnection, L.L.C.
	ER14-972-001 ER14-972-002 (not consolidated)	PJM Interconnection, L.L.C.
E-13	OMITTED	
E-14	EL15-43-000	Delta-Montrose Electric Association
E-15	EL09-63-000	City of Orangeburg, South Carolina
E-16	EL15-6-001	PáTu Wind Farm, LLC v. Portland General Electric Company
	QF06-17-003	PáTu Wind Farm, LLC
E-17	EL11-63-001	Louisiana Public Service Commission v. Entergy Corporation; Entergy Services, Inc.; Entergy Louisiana, LLC; Entergy Arkansas, Inc.; Entergy New Orleans, Inc.; Entergy Mississippi, Inc.; Entergy Gulf States Louisiana, L.L.C.; and Entergy Texas, Inc.
E-18	OMITTED	
E-19	ER15-696-000	PJM Interconnection, L.L.C.
E-20	EL15-45-000	Arkansas Electric Cooperative Corporation; Mississippi Delta Energy Agency; Clarksdale Public Utilities Commission; Public Service Commission of Yazoo City; and Hoosier Energy Rural Electric Cooperative, Inc. v. ALLETE, Inc.; Ameren Illinois Company; Ameren Missouri; Ameren Transmission Company of Illinois; American Transmission Company LLC; Cleco Power LLC; Duke Energy Business Services, LLC; Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Montana-Dakota Utilities Co.;

		Northern Indiana Public Service Company; Northern States Power Company-Minnesota; Northern States Power Company–Wisconsin; Otter Tail Power Company; and Southern Indiana Gas & Electric Company

HYDRO

H-1	CD15-18-001	Soldier Canyon Filter Plant
H-2	P-14581-001	Turlock Irrigation District and Modesto Irrigation District
H-3	P-13212-004	Kenai Hydro, LLC

CERTIFICATES

C-1	CP14-548-000 CP14-547-000	Natural Gas Pipeline Company of America LLC Devon Gas Services, L.P.

Kimberly D. Bose,
Secretary.

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151 FERC ¶ 61,225
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RR15-8-000

ORDER CONDITIONALLY ACCEPTING REVISIONS TO WORKING CAPITAL AND OPERATING RESERVE POLICY

(Issued June 18, 2015)

1. On March 6, 2015, North American Electric Reliability Corporation (NERC) filed proposed revisions to its Working Capital and Operating Reserve Policy (Reserve Policy). As discussed below, we conditionally accept NERC's proposed revisions to the Reserve Policy, subject to NERC submitting a compliance filing within 60 days of the date of this order.

I. Background

2. On August 22, 2011, the Commission's Office of Enforcement informed NERC by letter that it was commencing a performance audit of NERC pursuant to section 215 of the Federal Power Act (FPA).[1] The audit commencement letter stated that the performance audit would evaluate "NERC's budget formulation, administration, and execution[,] . . . will focus on the costs and resources used to achieve program objectives . . . [and] will cover the period from August 23, 2006 to the present."[2]

[1] 16 U.S.C. § 824o (2012).

[2] The Office of Enforcement's August 22, 2011 letter is available through the Commission's eLibrary document retrieval system in Docket No. FA11-21-000.

3. On May 4, 2012, the Office of Enforcement issued its performance audit report (Audit Report) by delegated letter order.[3] The Audit Report outlined 42 recommendations to remedy the audit findings and enhance performance of NERC's budget process. Specifically, Recommendation Nos. 1 and 2 recommended that NERC do as follows:

> 1. Establish more robust procedures and controls over NERC's use of working capital reserves.
>
> 2. Develop a transparent process that permits the Commission, the [Board of Trustees (Board)] and stakeholders opportunity to review the expenditure of funds approved for specific statutory activities to be redirected to unbudgeted activities, and develop and obtain Board approval of enhanced guidelines governing such expenditures, including criteria for determining when Board and Commission approval is required.[4]

4. On August 24, 2012, in accordance with Audit Recommendation No. 1, NERC submitted the Reserve Policy, governing its working capital and operating reserves, in Exhibit E of NERC's 2013 business plan and budget filing.[5] The Commission accepted the Reserve Policy as part of NERC's 2013 business plan and budget filing, on November 2, 2012.[6]

5. On January 16, 2013, the Commission approved a settlement between NERC and the Office of Enforcement regarding the audit findings.[7] The Settlement Agreement, *inter alia*, modified Recommendation No. 2 regarding NERC's Reserve Policy, by modifying the language of the recommendations and adding sub-requirements.[8]

6. Specifically, *inter alia*, revised Recommendation No. 2 requires NERC to "file for Commission review and approval … proposals to expend $500,000 or more from

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[3] *North American Electric Reliability Corp.*, Docket No. FA11-21-000 (May 4, 2012) (delegated letter order) (Audit Report Letter Order).

[4] Audit Report Letter Order, Audit Report at 7, 28-29.

[5] NERC, Petition, Docket No. RR12-13-000 (filed Aug. 24, 2013).

[6] *North American Electric Reliability Corp.*, 141 FERC ¶ 61,086 (2012).

[7] *North American Electric Reliability Corp.*, 142 FERC ¶ 61,042 (2013).

[8] *Id.*, Settlement Agreement at P 7.

operating reserves designated for 'unforeseen contingencies.'"[9] The Settlement Agreement stipulates that the need for Commission review and approval is triggered if any amount allocated from the unforeseen contingencies account of operating reserves plus any amount re-directed from previously budgeted funds is, in the aggregate, $500,000 or more for any one specific project or major activity in a program area.[10] The Settlement Agreement also requires NERC to file any proposed revisions to its Reserve Policy for Commission review and approval.[11]

7. On August 23, 2013, NERC submitted its 2014 business plan and budget for Commission approval. On November 1, 2013, while generally approving NERC's filing, the Commission, *inter alia*, rejected NERC's proposal to allocate to "restricted working capital" $3.8 million to offset future liabilities regarding lease agreements and directed NERC to submit a compliance filing concerning how it would allocate the $3.8 million consistent with its Reserve Policy.[12] In a compliance filing, NERC revised its Reserve Policy to further define working capital as "cash balances reasonably necessary to meet current and future obligations under any covenant, financial, or other obligation under the terms of any loan, credit, or lease agreement." NERC's compliance filing was accepted on January 3, 2014.[13]

II. Petition

8. NERC proposes to revise the Reserve Policy to include the following operating reserves: (1) future obligation reserve, (2) system operator certification reserve, (3) Cybersecurity Risk Information Sharing Program (CRISP) reserve, and (4) operating contingency reserve. NERC's revisions to the Reserve Policy also include the addition of

[9] *Id.* P 7(b)(ii).

[10] *Id.*

[11] *Id.* P 7(d) ("The provisions of Section 7(a), (b), and (c) are based on NERC's current Reserve Policy, which, *inter alia*, defines 'working capital reserves,' 'operating reserves,' 'known contingencies' and 'unforeseen contingencies.' NERC will file proposed revisions to the Reserve Policy that would alter any of those definitions, or would change the Reserve Policy's requirement that all excess funds be added to the unforeseen contingency operating reserves and expended in accordance with the Policy's unforeseen contingency guidelines, for Commission review and approval.").

[12] *North American Electric Reliability Corp.*, 145 FERC ¶ 61,097, at P 23 (2013).

[13] *North American Electric Reliability Corp.*, Docket Nos. RR13-9-001 and RR13-9-002 (Jan. 3, 2014) (delegated letter order).

an assessment stabilization reserve.[14] NERC maintains that the proposed categories reflect changes in NERC programs, eliminate unnecessary components, merge old reserve categories, and establish a new assessment stabilization reserve.[15]

9. NERC proposes to revise the Reserve Policy's definition of "working capital" so that it no longer includes "cash balances reasonably necessary to meet current and future obligations under any covenant, financial, or other obligation under the terms of any loan, credit, or lease agreement to which the company is a party," and, instead, establish the future obligation reserve for such needs. NERC states that funds to satisfy future contractual or covenant obligations are not needed to satisfy daily cash flow requirements and are more appropriately classified as a reserve. NERC proposes to define "working capital" as only funds needed to satisfy cash flow requirements throughout the year, while operating reserves will consist of reserves needed to support operations, including contractual and covenant obligations, as well as contingencies.[16]

10. NERC proposes to create an assessment stabilization reserve to mitigate year-to-year swings in assessments, which can result from a variety of factors, such as application of penalty funds collected, surplus funds available from a prior period, a need to replenish the operating contingency reserve, or significant but relatively short-term operating or capital spending needs.[17] NERC states that the goal of the reserve is to have changes in annual assessments track, within a reasonable band, changes in NERC's total annual budget, with the total budget reflecting prudent fiscal discipline and good stewardship of resources. NERC asserts that funds from the assessment stabilization reserve may not be used for any purpose inconsistent with the goal of the reserve except as otherwise approved by the Board.[18] NERC states that this provision provides additional flexibility for the Board in extreme and highly unusual circumstances in a particular year, such as an unexpected and significant litigation expense or a significant Bulk-Power System event that requires extraordinary investigation expenses.[19]

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[14] NERC Petition at 1-2; Revised Reserve Policy at 1.

[15] NERC Petition at 1-2.

[16] *Id.* at 5.

[17] NERC Petition at 8; Revised Reserve Policy at 2.

[18] *Id.*

[19] NERC Petition at 8.

11. With regard to the assessment stabilization reserve, NERC requests an exception pursuant to §1107.4 of the NERC Rules of Procedure. NERC notes that Rules of Procedure §1107.2 requires the use of penalty funds as a general offset to NERC's budget requirements for the subsequent fiscal year, but notes that §1107.4 provides that "Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority."[20] NERC requests an exception such that it may place penalty funds received prior to July 1 of a year into the assessment stabilization reserve, to be applied in a future budget to mitigate assessment volatility, rather than using the penalty funds as a general offset to NERC's budget requirement for the subsequent fiscal year. NERC indicates that these funds will continue to be used to reduce assessments, but in a future period rather than the next budget year.

12. NERC proposes to establish lower and upper bounds on operating contingency reserve levels equal to 3.5 percent and 7.0 percent, respectively, of NERC's total budgeted expenditures, excluding the CRISP and system operator certification reserves. NERC states that these bounds are intended to provide a reasonable "bandwidth" around the funding amount for operating contingency reserve.[21]

13. NERC proposes to increase the levels of expenditures from operating reserves that must be approved internally (i.e., by the NERC president and chief executive officer (CEO), the Finance and Audit Committee of the Board, and the Board itself). NERC's proposed revisions double each expenditure limit currently required for review by its respective levels of management or oversight. NERC notes that, because the current language referring to "known contingencies" and "unknown contingencies" is being replaced by the proposed operating contingency reserve category, NERC will treat the "unforeseen contingencies" references in Paragraph 7(b)(ii) of the Settlement Agreement as encompassing expenditures from the proposed operating contingency reserve.[22]

14. NERC proposes to eliminate the requirement that budgeted but unspent funds from a budget area be transferred to the unforeseen contingency operating reserve before the president and CEO can expend such funds in other budget areas. NERC's proposed language, instead, gives authority to the president and CEO to reallocate and expend those unspent funds elsewhere so long as NERC's overall approved budget is not exceeded and such expenditures are reported to the Finance and Audit Committee and

[20] NERC Petition at 10-11.

[21] *Id.* at 12.

[22] *Id.* at 15.

submitted in NERC's quarterly variance reports to the Commission.[23] NERC reiterates that any such expenditure and reallocation also will be subject to the Commission filing and approval requirements under Paragraph 7(b)(ii) of the Settlement Agreement if the dollar amount exceeds $500,000.[24]

15. NERC proposes to eliminate the provision in the Reserve Policy regarding review and approval requirements when attempting to add unbudgeted full-time equivalent employees (FTE) or headcount additions beyond what was budgeted for a particular fiscal year, regardless of the source and availability of funding. NERC states that this proposed change is appropriate because increases in its FTEs and headcount are not directly related to the management of operating reserves and are not appropriately included in the Reserve Policy. NERC states that if an increase in FTEs or headcount during a year above the budgeted levels requires either the expenditure of funds from an applicable reserve category or the reallocation of funds from one budget area to another, then the Reserve Policy provides for the appropriate review, approval, and reporting of the expenditures. NERC also contends that the quarterly variance reports that NERC submits to the Commission include information on actual versus budgeted FTEs.[25]

III. Notice of Filing

16. Notice of NERC's March 6, 2015 filing was published in the *Federal Register*, 80 Fed. Reg. 13,528 (2015), with interventions and protests due on or before March 27, 2015. No protests or interventions were filed.

IV. Discussion

17. We conditionally accept NERC's proposed revisions to the Reserve Policy, subject to NERC submitting a compliance filing within 60 days of the date of this order, as discussed below.

18. In its filing, NERC represents that any reallocation and expenditure of budgeted but unneeded funds would be subject to Paragraph 7(b)(ii) of the Settlement Agreement.[26] Further, NERC notes that the assessment stabilization reserve would only be used as approved by the Commission in NERC's business plan and budget filings,

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[23] *Id.* at 16; Revised Reserve Policy at 4.

[24] NERC Petition at 16.

[25] *Id.* at 20.

[26] *Id.* at 16.

except in extraordinary cases.[27] We expect that any extraordinary use of assessment stabilization reserve funds would also be subject to the limits and filing requirements under Paragraph 7(b)(ii) of the Settlement Agreement. We note, however, that such requirements are not articulated in the revised Reserve Policy. Thus, we direct NERC to submit a compliance filing within 60 days of the date of this order proposing revisions to the Reserve Policy to clarify that any reallocation and expenditure of budgeted funds, including from the assessment stabilization reserve, is subject to the requirements of Paragraph 7(b)(ii) of the Settlement Agreement.

19. While we accept, subject to the condition above, the proposed revisions to the Reserve Policy with regard to the assessment stabilization reserve, we find NERC's request for an exception regarding the use of penalty funds pursuant to NERC Rules of Procedure §1107.4 premature. Rather than providing a blanket exception, we find that any such exception is more appropriately addressed on a case-by-case basis, such as in NERC's annual business plan and budget submissions. In its petition, NERC represents that it may only request to inject into or withdraw funds from the assessment stabilization reserve through its annual business plan and budget submissions.[28] Thus, an exception under Rules of Procedure §1107.4 is not ripe in this proceeding. The Commission will consider the appropriateness of granting an exception under Rules of Procedure §1107.4 based on the specifics of each request by NERC in any future business plan and budget submission.

20. Finally, we note that NERC must continue to seek Commission approval of any future proposed changes to the NERC Reserve Policy as required by Paragraph 7(d) of the Settlement Agreement.

The Commission orders:

(A) NERC's proposed revisions to the Reserve Policy are hereby conditionally accepted, as discussed in the body of this order.

[27] *Id.* at 8-9.

[28] *Id.* at 9 ("any injection of funds into the Assessment Stabilization Reserve … or withdrawal of funds … [will be] subject to approval by the NERC Board and, ultimately, by the Commission as part of its approval of that year's business plan and budget").

(B) NERC is hereby directed to submit a compliance filing within 60 days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

151 FERC ¶ 61,230
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000]

Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards

(Issued June 18, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission proposes to approve Reliability Standards and definitions of terms submitted in three related petitions by the North American Electric Reliability Corporation (NERC), the Commission-approved Electric Reliability Organization. The Commission proposes to approve Reliability Standards EOP-011-1 (Emergency Operations) and PRC-010-1 (Undervoltage Load Shedding). According to NERC, the proposed Reliability Standards consolidate, streamline and clarify the existing requirements of certain currently-effective Emergency Preparedness and Operations (EOP) and Protection and Control (PRC) standards. The Commission also proposes to approve NERC's revised definition of the term "Remedial Action Scheme" as set forth in the NERC Glossary of Terms Used in Reliability Standards, and modifications of specified Reliability Standards to incorporate the revised definition. Further, the Commission proposes to approve the proposed implementation plans, and the retirement of certain currently-effective Reliability Standards. The Commission discusses concerns

regarding several of NERC's proposals and, depending on the comments provided in response, the Commission may direct NERC to develop further modifications to address the concerns and possibly delay the retirement of one currently-effective standard.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

151 FERC ¶ 61,230
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revisions to Emergency Operations Reliability Standards	Docket Nos.	RM15-7-000
Revisions to Undervoltage Load Shedding Reliability Standards		RM15-12-000
Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards		RM15-13-000

NOTICE OF PROPOSED RULEMAKING

(June 18, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve Reliability Standards and definitions of terms submitted in three related petitions by the North American Electric Reliability Corporation (NERC), the Commission-approved Electric Reliability Organization (ERO). In particular, the Commission proposes to approve Reliability Standards EOP-011-1 (Emergency Operations) and PRC-010-1 (Undervoltage Load Shedding). NERC explains that the proposed Reliability Standards consolidate, streamline, and clarify the existing requirements of certain currently-effective Emergency Preparedness and Operations (EOP) and Protection and Control (PRC) standards. The Commission also proposes to approve NERC's revised definition of the term "Remedial Action Scheme" as set forth in

[1] 16 U.S.C. 824o.

the NERC Glossary of Terms Used in Reliability Standards (NERC Glossary), and modifications of specified Reliability Standards to incorporate the revised definition. Further, the Commission proposes to approve assigned violation risk factors and violation severity levels, proposed implementation plans, and the retirement of certain currently-effective Reliability Standards. The Commission discusses concerns regarding several of NERC's proposals and, depending on the comments provided in response, the Commission may direct NERC to develop further modifications to address the concerns and possibly delay the retirement of one currently-effective standard.

I. Background

2. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[2] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight or by the Commission independently. In 2006, the Commission certified NERC as the ERO pursuant to FPA section 215.[3]

3. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including initial versions of EOP-001,

[2] 16 U.S.C. 824o.

[3] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

EOP-002, and EOP-003.[4] In addition, the Commission directed NERC to develop certain modifications to the EOP standards. In Order No. 693, the Commission also approved several Undervoltage Load Shedding (UVLS)-related Reliability Standards, including PRC-010-0, PRC-021-1 and PRC-022-1.[5] Also, the Commission directed NERC to modify Reliability Standard PRC-010-0 to develop an "integrated and coordinated" approach to all protection systems.[6] In Order No. 693, the Commission approved the NERC Glossary, including NERC's currently-effective Special Protection System and Remedial Action Scheme definitions.

II. NERC Petitions

4. NERC submitted three related petitions that we address together in this notice of proposed rulemaking (NOPR).[7]

A. NERC EOP Petition – Proposed Reliability Standard EOP-011-1 (Docket No. RM15-7-000)

5. On December 29, 2014, NERC submitted a petition seeking Commission approval of proposed Reliability Standard EOP-011-1 and a revised definition of

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[5] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1509, 1560 and 1565. The Commission neither approved nor remanded Reliability Standard PRC-020-1, explaining that the standard only applied to Regional Reliability Organizations. *Id*. P 1555.

[6] *Id.* P 1509.

[7] The proposed EOP and PRC Reliability Standards are not attached to this notice of proposed rulemaking, nor are the additional standards that NERC proposes to modify to incorporate the revised term Remedial Action Scheme. The proposed Reliability Standards are available on the Commission's eLibrary document retrieval system in the identified dockets and on the NERC website, www.nerc.com.

"Energy Emergency." NERC explains that proposed Reliability Standard EOP-011-1 consolidates the requirements in three existing Reliability Standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 "into a single Reliability Standard that clarifies the critical requirements for Emergency Operations while ensuring strong communication and coordination across the functional entities."[8] NERC seeks retirement of Reliability Standards EOP-001-2.1b, EOP-002-3.1 and EOP-003-2, as well as the approval of the associated implementation plan and violation risk factors and violation severity levels for Reliability Standard EOP-011-1 detailed in the petition. NERC also asserts that proposed Reliability Standard EOP-011-1 satisfies seven Commission directives set forth in Order No. 693.[9]

6. NERC states that the purpose of proposed Reliability Standard EOP-011-1 is "to address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plans to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator area."[10] NERC notes that Requirements R2 and R6 of the proposed Reliability Standard incorporate Attachment 1, which describes three energy emergency levels used by the

[8] NERC EOP Petition at 3.

[9] *Id.* at 12-18.

[10] *Id.* at 2.

reliability coordinator and the process for communicating the condition of a balancing authority experiencing an energy emergency.[11]

7. Proposed Reliability Standard EOP-011-1 includes six requirements, and is applicable to balancing authorities, reliability coordinators and transmission operators. Requirements R1 and R2 require transmission operators and balancing authorities to develop, maintain and implement reliability coordinator-reviewed operating plans to mitigate operating, capacity and energy emergencies.[12] Requirement R1 specifies elements for the plans "as applicable," which is intended to provide flexibility to account for regional differences and pre-existing emergency mitigation methods. NERC states that the requirement for transmission operators and balancing authorities to maintain operating plans includes the expectation that the plans are current and up-to-date.[13]

8. Requirement R3 requires reliability coordinators to review the operating plans submitted by transmission operators and balancing authorities and is designed to ensure

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[11] Attachment 1 describes three alert levels: Energy Emergency Alert Level 1 (all available generation resources in use, concern about sustaining required contingency reserves); Energy Emergency Alert Level 2 (load management procedures in effect, energy deficient balancing authority implements its emergency Operating Plan but maintains minimum contingency reserve requirements); and Energy Emergency Alert Level 3 (firm load interruption is imminent or in process, energy deficient balancing authority unable to maintain minimum contingency reserve requirements).

[12] Operating Plan is defined in the NERC Glossary as a "document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan."

[13] NERC EOP Petition at 8-9.

that there is appropriate coordination of reliability risks identified in the operating plans. In reviewing operating plans, reliability coordinators shall consider compatibility, coordination and inter-dependency with other entity operating plans and notify transmission operators and balancing authorities if revisions to their operating plans are necessary.[14]

9. Requirement R4 requires transmission operators and balancing authorities to resolve any issues identified by the reliability coordinator and resubmit their revised operating plans within a time period specified by the reliability coordinator. Requirement R5 requires each reliability coordinator to notify balancing authorities and transmission operators in its area, and neighboring reliability coordinators, within thirty minutes of receiving an emergency notification. Requirement R6 requires a reliability coordinator with a balancing authority experiencing a potential or actual energy emergency to declare an energy emergency alert in accordance with Attachment 1.

10. Proposed Reliability Standard EOP-011-1 also includes the following revised definition of Energy Emergency:

> Energy Emergency—A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

NERC explains that the proposed revised definition is intended to clarify that an energy emergency is not limited to a load-serving entity and, based on a review of the impact on

[14] *Id.* at 10-11.

the body of NERC Reliability Standards, "does not change the reliability intent of other requirements of Definitions."[15]

B. NERC PRC Petition – Proposed Reliability Standard PRC-010-1 (Docket No. RM15-12-000)

11. On February 6, 2015, NERC submitted a petition seeking approval of proposed Reliability Standard PRC-010-1 (Undervoltage Load Shedding), approval of a revised definition of Undervoltage Load Shedding Program (UVLS Program) for inclusion in the NERC Glossary, the implementation plan for the proposed Reliability Standard and the associated violation risk factors and violation severity levels and retirement of four PRC Reliability Standards.[16]

12. In its petition, NERC states that proposed Reliability Standard PRC-010-1 is a single, comprehensive standard that addresses the same reliability principles outlined in the four currently-effective UVLS-related Reliability Standards.[17] NERC explains that the purpose of proposed Reliability Standard PRC-010-1 is to "establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs" as directed by the Commission in Order No. 693.[18] Also,

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[15] *Id.* at 18.

[16] Reliability Standard PRC-010-0 (Assessment of the Design and Effectiveness of UVLS Program); Reliability Standard PRC-020-1 (Under-Voltage Load Shedding Program Database); Reliability Standard PRC-021-1 (Under-Voltage Load Shedding Program Data); and Reliability Standard PRC-022-1 (Under-Voltage Load Shedding Program Performance).

[17] NERC PRC Petition at 14.

[18] *Id*. (citing Order No. 693, FERC Stats & Regs ¶ 31,242 at P 1509).

according to NERC, proposed Reliability Standard PRC-010-1 replaces the applicability to and involvement of "Regional Reliability Organization" in Reliability Standards PRC-020-1 and PRC-021-1 and consolidates the four currently-effective UVLS-Related Standards into one comprehensive standard. NERC states that proposed Reliability Standard PRC-010-1 "reflects consideration of the 2003 Blackout Report recommendations,"[19] particularly, Recommendation 21 for NERC to "make more effective and wider use of system protection measures"[20] and Recommendation 21C that "NERC determine the goals and principles needed to establish an integrated approach to relay protection for generators and transmission lines, as well as of UFLS and UVLS programs."[21]

13. Proposed Reliability Standard PRC-010-1 incorporates a proposed definition of UVLS Program, which reads:

> **Undervoltage Load Shedding Program (UVLS Program)**: An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

NERC explains that "to ensure that the applicability of the proposed Reliability Standard covers undervoltage-based load shedding systems whose performance has an impact on

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[19] NERC PRC Petition at 2 (citing the U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April, 2004 (2003 Blackout Report)).

[20] NERC PRC Petition at 4 (citing 2003 Blackout Report at 3, 158).

[21] NERC PRC Petition at 6.

system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System. By focusing on the enumerated risks, the definition is meant to exclude locally-applied relays that are not designed to mitigate wide-area voltage collapse."[22] NERC states that the proposed UVLS Program definition "clearly identifies and separates centrally controlled undervoltage-based load shedding, which is now addressed by the proposed definition of Remedial Action Scheme."[23]

14. Proposed Reliability Standard PRC-010-1 applies to planning coordinators and transmission planners because "either may be responsible for designing and coordinating the UVLS Program…[and] also applies to Distribution Providers and Transmission Owners responsible for the ownership, operation and control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator."[24] NERC explains that the planning coordinator or transmission planner that establishes a UVLS Program is responsible for identifying the UVLS equipment and the necessary distribution provider and transmission owner (referred to as "UVLS entities" in the Applicability section) that performs the required actions.

15. NERC states that proposed Reliability Standard PRC-010-1 "applies only after an entity has determined the need for a UVLS Program as a result of its own planning

[22] *Id.* at 16.

[23] *Id.* at 15. NERC's petition for approval of the proposed definition of Remedial Action Scheme (Docket No. RM15-13-000) is discussed below.

[24] *Id.*

studies."[25] NERC explains that the eight requirements in proposed Reliability Standard PRC-010-1 meet four primary objectives: (1) the proposed standard requires applicable entities to evaluate a UVLS Program's effectiveness prior to implementation, including coordination with other protection systems and generator voltage ride-through capabilities;(2) applicable entities must comply with UVLS program specifications and implementation schedule; (3) applicable entities must perform periodic assessment and performance analysis; and (4) applicable entities must maintain and share UVLS Program data.

16. Proposed Requirement R1 requires each planning coordinator or transmission planner that is developing a UVLS Program to evaluate the viability and effectiveness of its program before implementation to confirm its effectiveness in resolving the undervoltage conditions for which it was designed, and that it is integrated through coordination with generator ride-through capabilities and other protection and control systems. Also, the planning coordinator or transmission planner must provide the UVLS Program specifications and implementation schedule to the applicable UVLS entities. Requirement R2 requires UVLS entities to meet the UVLS Program's specifications and implementation schedule provided by the planning coordinator or transmission planner or address any necessary corrective actions in accordance with Requirement R5.

17. Requirement R3 requires each planning coordinator or transmission planner to perform periodic comprehensive assessments at least every 60 calendar months to ensure

[25] *Id.* at 14.

continued effectiveness of the UVLS program, including whether the program resolves identified undervoltage issues and that it is integrated and coordinated with generator voltage ride-through capabilities and other specified protection and control systems. Requirement R4 requires each planning coordinator or transmission planner to commence a timely assessment of a voltage excursion subject to the UVLS Program, within twelve calendar months of the event, to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event. Requirement R5 requires a planning coordinator or transmission planner to develop a corrective action plan for any program deficiencies identified during an assessment performed under either Requirement R3 or R4, and provide an implementation schedule to UVLS entities within three calendar months of its completion.

18. Pursuant to Requirement R6, a planning coordinator must update the data necessary to model its UVLS Program for use in event analyses and program assessments at least each calendar year. Requirement R7 requires each UVLS entity to provide data to its planning coordinator, according to the planning coordinator's format and schedule, to support maintenance of the UVLS Program database. Requirement R8 requires a planning coordinator to provide its UVLS Program database to other planning coordinators and transmission planners within its Interconnection, and other functional entities with a reliability need, within thirty calendar days of a written request.

19. NERC proposes that PRC-010-1 and the revised definition of UVLS Program shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard and definition are approved by the

Commission. NERC also proposes to retire PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1 at midnight of the day immediately prior to the effective date of PRC-010-1.[26] Further, NERC explains that proposed Reliability Standard PRC-010-1 addresses reliability obligations that are set forth in Requirements R2, R4 and R7 of currently-effective Reliability Standard EOP-003-2.[27] Since NERC has proposed to retire EOP-003-2 in the petition seeking approval of proposed Reliability Standard EOP-011-1 (Docket No. RM15-7-00, discussed above), concurrent Commission action on the two petitions will prevent a possible reliability gap.

C. NERC RAS Petition – Revisions to the Definition of "Remedial Action Scheme" (Docket No. RM15-13-000)

20. On February 3, 2015, NERC submitted a petition seeking approval of a proposed revised definition of Remedial Action Scheme in the NERC Glossary. In addition, NERC seeks approval of modified Reliability Standards that incorporate the new definition of Remedial Action Scheme and eliminate use of the term Special Protection System.[28] NERC states that the defined terms Special Protection System and Remedial Action Scheme are currently used interchangeably throughout the NERC Regions and in

[26] *Id.* Ex. B (Implementation Plan).

[27] *See* NERC EOP Petition at 23.

[28] NERC RAS Petition at 1-2. NERC proposes to modify the following Reliability Standards to incorporate the proposed definition of Remedial Action Scheme and eliminate use of the term Special Protection System: EOP-004-3, PRC-005-3(ii), PRC-023-4, FAC-010-3, TPL-001-0.1(i), FAC-011-3, TPL-002-0(i)b, MOD-030-3, TPL-003-0(i)b, MOD-029-2a, PRC-015-1, TPL-004-0(i)a, PRC-004-WECC-2, PRC-016-1, PRC-001-1.1(i), PRC-005-2(ii), and PRC-017-1. NERC does not propose any changes to the violation risk factors or violation severity levels for the modified standards.

various Reliability Standards. NERC explains that "[a]lthough these defined terms share a common definition in the NERC Glossary of Terms today, their use and application have been inconsistent as a result of a lack of granularity in the definition and varied regional uses of the terms. The proposed revisions add clarity and granularity that will allow for proper identification of Remedial Action Schemes and a more consistent application of related Reliability Standards."[29]

21. NERC states that the revised definition of Remedial Action Scheme consists of a "core" definition, including a list of objectives and a separate list of exclusions for certain schemes or systems not intended to be covered by the revised definition.[30] NERC explains that it is proposing a broad definition because of "all the possible scenarios an entity may develop" for its Remedial Action Scheme and a "very specific, narrow definition may unintentionally exclude schemes that should be covered."[31] Accordingly, NERC proposes the following revised "core" definition of Remedial Action Scheme:

> A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). (sic) RAS accomplish objectives such as:
> - Meet requirements identified in the NERC Reliability Standards;
> - Maintain Bulk Electric System (BES) stability;

[29] *Id.* at 4-5.

[30] *Id.* at 16. NERC notes that "for each exclusion, the scheme or system could still classify as a Remedial Action Scheme if employed in a broader scheme that meets the definition of Remedial Action Scheme."

[31] *Id.* at 17.

- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The definition then lists fourteen exclusions, describing specific schemes and systems that do not constitute a Remedial Action Scheme, because each is either a protection function, a control function, a combination of both, or used for system reconfiguration.[32]

22. In the implementation plan, NERC proposes an effective date for the revised Reliability Standards and the revised definition of "Remedial Action Scheme" on the first day of the first calendar quarter that is twelve months after Commission approval.[33] NERC also proposes that for entities with existing schemes that become newly classified as "Remedial Action Schemes" resulting from the application of the revised definition, the entities will have additional time of up to twenty-four months from the effective date to be fully compliant with all applicable Reliability Standards.[34] Further, NERC asks the Commission to take final action concurrently with the NERC petition on proposed Reliability Standard PRC-010-1 (Docket No. RM15-12-000) because "[t]he proposed definitions of UVLS Program and Remedial Action Scheme in each project have been coordinated to cover centrally controlled UVLS as a Remedial Action Scheme. Final

[32] *Id.* at 18.

[33] *Id.* at 15-16.

[34] NERC RAS Petition, EX. C (Implementation Plan) at 4.

action by the Commission is needed contemporaneously on both petitions to facilitate implementation and avoid a gap in coverage of centrally controlled UVLS."[35]

III. Discussion

23. Pursuant to section 215(d) of the FPA, the Commission proposes to approve as just, reasonable, not unduly discriminatory or preferential, and in the public interest the proposed Reliability Standards and NERC Glossary definitions set forth in NERC's three petitions pertaining to EOP-011-1, PRC-010-1 and a revised definition of Remedial Action Scheme. As discussed below, the Commission believes that the modified Reliability Standards provide greater clarity, and the consolidated EOP and PRC standards will provide additional efficiencies for responsible entities.

A. Proposed Reliability Standard EOP-011-1

24. Pursuant to section 215(d) of the FPA, we propose to approve proposed Reliability Standard EOP-011-1 and the proposed new Energy Emergency definition, as well as the proposed violation risk factors and violation severity levels and implementation plan. We agree with NERC that proposed EOP-011-1 consolidates and reorganizes previously approved standards, and proposes modifications based on current operating practices and experience. We believe that the Reliability Standard enhances reliability by requiring that actions necessary to mitigate capacity and energy emergencies are focused in

single operating plans, and ensures communication and coordination among relevant

[35] NERC RAS Petition at 25.

entities during emergency operations. Also, we are satisfied that the NERC petition adequately addresses the relevant Order No. 693 directives.[36]

B. Proposed Reliability Standard PRC-010-1

25. Pursuant to section 215 of the FPA, we propose to approve proposed Reliability Standard PRC-010-1 as just, reasonable, not unduly discriminatory or preferential and in the public interest. We also propose to approve the proposed, revised definition of UVLS Program for inclusion in the NERC Glossary, the implementation plan and the associated violation risk factors and violation severity levels. Likewise, we propose to approve the retirement of PRC-010-0, PRC-020-1 and PRC-021-1.[37] However, for the reasons explained below, we are concerned whether it is appropriate to retire PRC-022-1, as

[36] Currently effective EOP-002-3.1 applies, *inter alia*, to load-serving entities. Proposed EOP-011-1, which would replace EOP-002-3.1, would apply to balancing authorities, reliability coordinators and transmission operators, but not load-serving entities. The removal of load-serving entities raises questions on who would perform the roles traditionally performed by load-serving entities. For instance, NERC's Functional Model indicates that a load-serving entity has real-time responsibility to receive requests from a balancing authority to voluntarily curtail load and communicate such requests for voluntary load curtailment to end-use customers as directed by the balancing authority. In addition, NERC's Functional Model indicates that a balancing authority has a real-time function to coordinate the use of controllable loads with load-serving entities. The Commission notes that NERC is required to make a compliance filing in July 2015 in Docket No. RR15-4-000. The Commission's decision on that filing will guide our action on this question in this proceeding.

[37] As noted above, the Commission in Order No. 693 did not approve or remand proposed Reliability Standard PRC-020-1 but, rather, took no action on the Reliability Standard pending the receipt of additional information. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1555. Approval of Reliability Standard PRC-010-1, as proposed herein, will render PRC-020-1 "retired," i.e., withdrawn, and no longer pending before the Commission.

NERC requests, before an acceptable replacement Reliability Standard is in place to address the potential misoperation of UVLS equipment.

26. The Commission agrees with NERC that proposed Reliability Standard PRC-010-1 will improve system reliability by establishing an integrated and coordinated approach to the design, evaluation and reliable operation of UVLS Programs, and therefore satisfies the Commission's directive issued in Order No. 693.[38] We also propose to approve the proposed UVLS Program definition and agree that it "clearly identifies and separates centrally controlled undervoltage-based load shedding, which is now addressed by the proposed definition of Remedial Action Scheme."[39]

27. In the "Guidelines for UVLS Program Definition," NERC provides an example of a "BES subsystem," in the diagram below, illustrating a UVLS system that would not be included in the definition of UVLS Program if the consequences of the contingency do not impact the BES.[40] The Commission seeks clarification whether this example illustrates a centrally controlled UVLS and would therefore be considered a Remedial Action Scheme.[41] The Commission also seeks clarification regarding the use of the term "BES subsystem," since the term is not defined in the NERC Glossary. Depending on the response from NERC and others, a directive for further modification may be

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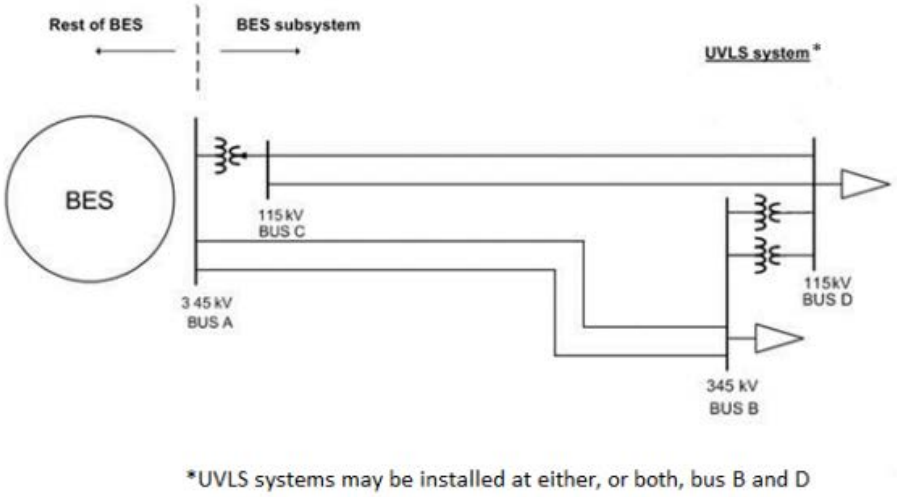
[38] Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1509.

[39] NERC PRC Petition at 15. NERC's proposed revised definition of Remedial Action Scheme (Docket No. RM15-13-000) is addressed elsewhere in this NOPR.

[40] NERC PRC Petition, Ex. A (Proposed Reliability Standard PRC-010-1) at 12.

[41] *Id.* at 3.

appropriate to ensure that the UVLS standards and related NERC guidance are consistent with the Commission-approved definition of "bulk electric system."[42]



28. NERC proposes to retire Reliability Standard PRC-022-1, which requires transmission operators, load-serving entities and distribution providers to analyze and document all UVLS operations and misoperations. Requirement R1.5 of this Reliability Standard requires that an applicable entity's analysis and documentation should include "[f]or any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature." Proposed Reliability Standard PRC-010-1, Requirement R5 addresses deficiencies in UVLS Programs that a planning coordinator or transmission planner identifies during assessments performed in accordance with either Requirement R3 (periodic UVLS Program effectiveness evaluations) or Requirement R4 (evaluations to

[42] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013), *order on reh'g and clarification*, 144 FERC ¶ 61,174 (2013), *aff'd sub nom.*, *New York* v. *FERC*, 783 F.3d 946 (2d. Cir. 2015).

assess UVLS Program responses to voltage excursions), and requires the entities to develop a Corrective Action Plan to address the deficiencies.

29. NERC correctly states that "[w]hen a UVLS Program does not function as expected and designed during a voltage excursion event, this presents a risk to system reliability."[43] However, we are not persuaded that proposed Reliability Standard PRC-010-1, Requirement R4 is an adequate replacement for currently-effective PRC-022-1, which contains requirements specifically addressing misoperations. Accordingly, we propose to deny NERC's proposal to retire currently-effective Reliability Standard PRC-022-1 concurrent with the effective date of proposed PRC-010-1. Rather, we propose that Reliability Standard PRC-022-1 remain in effect until an acceptable replacement standard is approved and implemented.[44]

C. Revised Definition of Remedial Action Scheme

30. Pursuant to section 215(d) of the FPA, the Commission proposes to approve the proposed definition of Remedial Action Scheme, the proposed exclusions, the proposed Reliability Standards and proposed implementation plan, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We are persuaded that the use of

[43] *Id.* at 20.

[44] In the PRC Petition, NERC indicates that UVLS misoperations are currently being addressed in Project 2008-02.2 Phase 2 Undervoltage Load Shedding (UVLS): Misoperations. NERC states that "[t]his phase of the UVLS project will address Misoperation of UVLS equipment to complete the work anticipated by the two standard drafting teams." *Id.* at 23. The Commission notes that, on June 9, 2015, NERC filed proposed Reliability Standards PRC-010-2 and PRC-004-5, which include requirements and applicability criteria pertaining to UVLS misoperations.

a broad, core definition with a wide scope, accompanied by a list of specific exclusions will help avoid confusion and achieve a uniform understanding across all the Regional Entities of the proper classification of what schemes and systems constitute a Remedial Action Scheme. We agree with NERC that the proposed definition will improve reliability by eliminating ambiguity and promoting the proper, consistent identification of Remedial Action Schemes and more consistency in the application of related Reliability Standards.[45]

IV. Information Collection Statement

31. The collection of information contained in this Notice of Proposed Rulemaking is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[46] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[47] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

32. We solicit comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any

[45] NERC RAS Petition at 14-16.

[46] 44 U.S.C. 3507(d).

[47] 5 CFR 1320.11.

suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically, the Commission asks that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

A. Proposed Reliability Standard EOP-011-1

33. Public Reporting Burden: As of May 2015, there are 99 balancing authorities, 15 reliability coordinators and 171 transmission operators registered with NERC. These registered entities will have to comply with 6-8 new requirements in the proposed Reliability Standard EOP-011-1. As proposed, each registered balancing authority will have to comply with Requirements R2, R4, and, under certain circumstances, R5. Each reliability coordinator will have to comply with Requirements R1 and its subparts, R2 and its subparts, R3 and its subparts, R5 and R6. Each transmission operator will have to comply with Requirements R1 and its subparts and R4.

34. Proposed Reliability Standard EOP-011-1 replaces a combined total of 40 requirements or subparts that are found in Reliability Standards EOP-001-2.1b, EOP-002-3.1 and EOP-003-2. These three Reliability Standards are proposed to be retired, concurrent with the effective date of proposed Reliability Standard EOP-011-1. Accordingly, the requirements in proposed Reliability Standard EOP-011-1 do not create any new burdens for applicable balancing authorities or transmission operators because the requirements in Reliability Standard EOP-011-1 are already burdens or tasks imposed on this set of registered entities by Reliability Standards EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 under FERC-725A (1902-0244).

35. Proposed Reliability Standard EOP-011-1 requires reliability coordinators to perform the additional tasks of reviewing, correcting, and coordinating their balancing authorities' and transmission operators' operating procedures for emergency conditions. The Commission estimates that these tasks will add approximately 1,500 man-hours per year for each reliability coordinator as described in detail in the following table:

RM15-7-000 (Mandatory Reliability Standards: Reliability Standard EOP-011-1)						
	Number of Applicable Registered Entities (1)	***Annual Number of Responses per Respondent (2)***	***Total Number of Responses (1)*(2)=(3)***	***Average Burden (Hours) & Cost Per Response (4)***	***Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)***	***Cost per Respondent ($) (5)÷(1)***
RC tasks necessary for EOP-011-1 compliance	11	1	11	1,500 $92,387[48]	16,500 $1,016,257	$92,387

B. Proposed Reliability Standard PRC-010-1

36. Public Reporting Burden: As of May 2015, there are 450 registered distribution providers and 175 transmission planners that are not overlapping in their registration with the distribution provider registration. We estimate that five percent of all distribution providers (23) and transmission planners (9) have under voltage load shedding programs that fall under the proposed Reliability Standard. The proposed Reliability Standard is applicable to planning coordinators and transmission planners, distribution providers and

[48] The 1,500 hour figure is broken into 1,300 hours at the engineer wage rate and 200 hours at the clerk wage rate. These estimates assume that the engineer's wage rate will be $66.35 and the clerk's wage rate will be $30.66. These figures are taken from the Bureau of Labor Statistics at http://www.bls.gov/oes/current/naics2_22.htm; Occupation Code: 17-2071 (engineer) and 43-4071 (clerk).

transmission owners. However, only distribution providers and transmission owners would be responsible for the incremental compliance burden under proposed Reliability Standard PRC-010-1, Requirement R2, as described in detail in the following table:

RM15-12-000 (Mandatory Reliability Standards: Reliability Standard PRC-010-1)[49]						
	Number of Applicable Registered Entities (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden (Hours) & Cost Per Response (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
DP – Requirement 2	23	1	23	36[50] $1,906.32	828 $43,845.36	$1,906
TP - Requirement 2	3	1	3	36[51] $1,906.32	324 $17,156.07	$1,906
DP - Requirement 2 Data Retention	23	1	23	12 $367.92[52]	276 $8,462.16	$368
TP – Requirement 2 Data Retention	3	1	3	12 $367.92	108 $3,311.28	$368
TOTAL					$72,774.87	

[49] DP = distribution provider and TP = transmission planner.

[50] The 36 hour figure is broken into 24 hours at the engineer wage rate and 12 hours at the clerk wage rate. These estimates assume that the engineer's wage rate will be $66.35 and the clerk's wage rate will be $30.66. These figures are taken from the Bureau of Labor Statistics at http://www.bls.gov/oes/current/naics2_22.htm; Occupation Code: 17-2071 (engineer) and 43-4071 (clerk).

[51] *Id.*

[52] Clerk's wage rate is used for managing data retention.

C. Remedial Action Scheme Revisions

37. Public Reporting Burden: The Commission approved the definition of Special Protection System (Remedial Action Scheme) in Order No. 693. We propose to approve a revision to the previously approved definition. The proposed revisions to the Remedial Action Scheme definition and proposed Reliability Standards are not expected to result in changes to the scope of systems covered by the proposed Reliability Standards and other Reliability Standards that include the term Remedial Action Scheme. Therefore, the Commission does not expect the proposed revisions to affect applicable entities' current reporting burden.

FERC-725G4, Mandatory Reliability Standards: Reliability Standard PRC-010-1 (Undervoltage Load Shedding).

FERC-725S, Mandatory Reliability Standards: Reliability Standard EOP-011-1 (Emergency Operations).

Action: Proposed Collection of Information.

OMB Control No: OMB Control No. 1902-0270 (FERC-725S); OMB Control No. 1902-TBD (FERC-725G4).

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: One time and on-going.

Necessity of the Information: The proposed approval of the proposed Reliability Standards implements the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the proposed Reliability Standards

consolidate, streamline and clarify the existing requirements of certain currently-effective Emergency Preparedness and Operations and Protection and Control Reliability Standards.

38. Internal review: The Commission has reviewed the requirements pertaining to proposed Reliability Standards PRC-010-1 and EOP-011-1 and made a determination that the proposed requirements of these Reliability Standards are necessary to implement section 215 of the FPA. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

39. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

40. Comments concerning the information collections proposed in this NOPR and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference the docket

numbers of this Notice of Proposed Rulemaking (Docket Nos. RM15-13-000, RM15-12-000, and RM15-7-000) in your submission.

V. Regulatory Flexibility Act Analysis

41. The Regulatory Flexibility Act of 1980 (RFA)[53] generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities. The immediate rulemaking proposes action on three separate, but related, NERC petitions. As discussed above, the consolidated EOP standard and consolidated PRC standards are intended to provide additional efficiencies for responsible entities. Thus, the Commission estimates that the rulemaking will impose only a minimal additional burden on responsible entities, as described below. Proposed Reliability Standard EOP-011-1 is expected to impose an additional burden on 11 entities (reliability coordinators). The remaining 270 entities (balancing authorities and transmission operators and a combination thereof) will maintain the existing levels of burden. Comparison of the applicable entities with FERC's small business data indicates that approximately 7 of the 11 entities are small entities affected by this proposed Reliability Standard.[54]

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[53] 5 U.S.C. 601-12.

[54] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we use a 500 employee threshold for each affected entity. Each entity is classified as Electric Bulk Power Transmission and Control (NAICS code 221121).

42. On average, each small entity affected may have a one-time cost of $92,387, representing a one-time review of the program for each entity, consisting of 1,500 man-hours at $66.35/hour (for engineers) and $30.66/hour (for record clerks), as explained above in the information collection statement. Proposed Reliability Standard PRC-010-1 is expected to impose an additional burden on 26 entities (distribution providers and transmission planners or a combination thereof). Comparison of the applicable entities with FERC's small business data indicates that approximately 8 are small entities affected by this proposed Reliability Standard.

43. On average, each small entity affected may have a cost of $1,906, representing a one-time review of the program for each entity, consisting of 96 man-hours at $66.35/hour (for engineers) and $30.66/hour (for record clerks), as explained above in the information collection statement. The Commission estimates that the modified definition of the term Remedial Action Scheme and related modifications to Reliability Standards will have no cost impact on applicable entities, including any small entities.

44. The Commission estimates that the combined impact of proposed Reliability Standards EOP-011-1 and PRC-010-1in this NOPR would impose an additional burden on a total of 47 entities. Further, the Commission estimates that 15 respondents are small entities affected by these proposed Reliability Standards. On average, each small entity affected may have a cost of $92,387 and $1,906 (EOP-011-1 and PRC-010-1 respectively), representing a one-time review of the program for each entity. The Commission does not consider these costs to be a significant economic impact on small entities. Accordingly, the Commission certifies that this rulemaking will not have a

significant economic impact on a substantial number of small entities. The Commission seeks comment on this certification.

VI. Environmental Analysis

45. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[55] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[56] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VII. Comment Procedures

46. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket Nos. RM15-13-000, RM15-12-000, and RM15-7-000, and must include the commenter's name, the organization they represent, if applicable, and address.

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[55] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[56] 18 CFR 380.4(a)(2)(ii).

47. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

48. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

49. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

50. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

51. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and

Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

52. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

151 FERC ¶ 61,236
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-16-000]

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards

(June 18, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Commission proposes to approve revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, developed by the North American Electric Reliability Corporation, which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards.

DATES: Comments are due **[INSERT DATE 60 Days after publication in the FEDERAL REGISTER]**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

  Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

151 FERC ¶ 61,236
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards — Docket No. RM15-16-000

NOTICE OF PROPOSED RULEMAKING

(June 18, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve revisions to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards, developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). The Commission believes that the proposed TOP and IRO Reliability Standards improve on the currently-effective standards by providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities. The Commission also believes that the revised TOP Reliability Standards eliminate gaps and ambiguities in the currently-effective TOP requirements and improve efficiency by

[1] 16 U.S.C. 824o (2012).

incorporating the necessary requirements from the eight currently-effective TOP Reliability Standards into three cohesive, comprehensive Reliability Standards. Further, the Commission believes that the proposed standards clarify and improve upon the currently-effective TOP and IRO Reliability Standards by designating requirements in the proposed standards that apply to transmission operators for the TOP standards and reliability coordinators for the IRO standards. Thus, the Commission proposes to find that there are benefits to clarifying and bringing efficiencies to the TOP and IRO Reliability Standards, consistent with the Commission's policy promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently-effective requirements or have little reliability benefit.[2]

2. The Commission also proposes to find that NERC has adequately addressed the concerns raised by the Commission in the Notice of Proposed Rulemaking (Remand NOPR) issued in November 2013.[3] In the Remand NOPR, the Commission proposed to remand an earlier version of proposed TOP and IRO Standards due to concerns regarding the proposed treatment of system operating limits (SOLs) and interconnection reliability

[2] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

[3] *Monitoring System Conditions - Transmission Operations Reliability Standard, Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards*, Notice of Proposed Rulemaking, 145 FERC ¶ 61,158 (2013). Concurrent with filing the proposed TOP/IRO standards in the immediate proceeding, NERC submitted a motion to withdraw the earlier petition that was the subject of the Remand NOPR. No protests to the motion were filed and the petition was withdrawn pursuant to 18 CFR § 385.216(b).

operating limits (IROLs) and concerns about outage coordination. Further, the Commission proposes to approve the definitions for operational planning analysis and real-time assessment, and the violation severity level and violation risk factor assignments.

3. While proposing to approve the TOP and IRO Reliability Standards, below the Commission seeks clarifying comments addressing four issues: (A) possible inconsistencies in identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of the load-serving entity as an applicable entity for proposed Reliability Standard TOP-001-3; and (D) data exchange capabilities. Based on comments and information received on these issues, the Commission may issue directives as appropriate.

I. Background

4. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 initial Reliability Standards filed by NERC, including the existing TOP and IRO Reliability Standards.[4] In

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

addition, in Order No. 748, the Commission approved revisions to the IRO Reliability Standards.[5]

5. On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards to replace the eight currently-effective TOP standards.[6] Additionally, on April 16, 2013, in Docket No. RM13-15-000, NERC submitted for Commission approval four revised IRO Reliability Standards to replace six currently-effective IRO Reliability Standards. On November 21, 2013, the Commission issued the Remand NOPR in which the Commission expressed concern that NERC had "removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards."[7] The Commission identified two main concerns and asked for clarification and comment on a number of other issues. Among other things, the Commission expressed concern that the proposed TOP Reliability Standards did not require transmission operators to plan and operate within all SOLs, which is a

[5] *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011).

[6] On April 5, 2013, in Docket No. RM13-12-000 NERC proposed revisions to Reliability Standard TOP-006-3 to clarify that transmission operators are responsible for monitoring and reporting available transmission resources and that balancing authorities are responsible for monitoring and reporting available generation resources.

[7] Remand NOPR, 145 FERC ¶ 61,158 at P 4.

requirement in the currently-effective standards. In addition, the Commission expressed concern that the proposed IRO Reliability Standards did not require outage coordination.

6. On December 20, 2013, NERC filed a motion requesting that the Commission defer action, until January 31, 2015, to allow NERC time to consider the reliability concerns raised by the Commission in the Remand NOPR. The Commission granted that motion on January 14, 2014.[8] In response to the Remand NOPR, NERC initiated Project 2014-03 to develop further revisions to the TOP and IRO Reliability Standards.

NERC Petition

7. On March 18, 2015, as supplemented on May 12, 2015, NERC submitted a petition seeking approval of two sets of Reliability Standards to replace the currently-effective TOP and IRO Reliability Standards. NERC states that the proposed TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of transmission operators, with certain requirements applying to the roles and responsibilities of the balancing authority. NERC adds that the proposed IRO Reliability Standards set forth the responsibility and authority of reliability coordinators to provide for reliable operations. According to NERC, reliability coordinators have an essential role in

[8] *Monitoring System Conditions- Transmission Operations Reliability Standard, Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards,* Order Granting Motion to Defer Action, 146 FERC ¶ 61,023 (2014).

ensuring reliable operations, as they are the functional entities with the highest level of authority and have the wide-area view of the bulk electric system. [9]

8. NERC states that the proposed Reliability Standards include improvements over the currently effective TOP and IRO Reliability Standards in key areas such as: (1) operating within SOLs and IROLs; (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data.

9. NERC states that the proposed TOP and IRO Reliability Standards address the coordinated efforts to plan and reliably operate the bulk electric system under both normal and abnormal conditions. NERC states that the proposed Reliability Standards provide a comprehensive framework for reliable operations, with important improvements to ensure the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning. NERC explains that the proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. According to NERC, the proposed Reliability Standards help to ensure that reliability coordinators and transmission operators work together, and with other functional entities, to operate the bulk electric

[9] The TOP and IRO Reliability Standards are not attached to this NOPR. The complete text of the Reliability Standards is available on the Commission's eLibrary document retrieval system in Docket No. RM15-16 and is posted on the ERO's web site, *available at*: http://www.nerc.com.

system within SOLs and IROLs.[10] Further, NERC explains that SOLs and IROLs are vital concepts in the Reliability Standards because they establish acceptable performance criteria both pre- and post-contingency to maintain reliable bulk electric system operations. NERC states that when any facility rating or stability limit is exceeded, or expected to be exceeded, these conditions should be mitigated to avoid the possibility of further deteriorating system conditions and the potential for a cascading event. In addition, NERC states that the standard drafting team developed a white paper on SOL definition and exceedance criteria which clarified the team's position on establishing and exceeding SOLs, and on implementing operating plans to mitigate exceedances. The SOL white paper explains the links between relevant reliability standards and reliability concepts to establish a common understanding necessary for developing effective operating plans to mitigate SOL exceedances.[11]

10. NERC states that it reviewed the report on the Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations ("2011 Southwest Outage Blackout Report") that includes findings and recommendations applicable to transmission

[10] The NERC Glossary of Terms defines IROL as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System." In turn, NERC defines SOL as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. …."

[11] NERC Petition at 46 and Exhibit E, "White Paper on System Operating Limit Definition and Exceedance Clarification."

operators, balancing authorities and reliability coordinators, and provides explanations of how the proposed Reliability Standards address the reliability issues identified following the 2011 Southwest Outage Blackout Report. Further, NERC states that it addressed outstanding Commission directives relevant to the proposed TOP and IRO Reliability Standards.

Revisions to TOP Standards

11. NERC proposes three TOP Reliability Standards to replace the existing suite of TOP standards. The proposed TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of transmission operators. Among other things, NERC states that the proposed revisions to the TOP Reliability Standards help ensure that transmission operators plan and operate within all SOLs.

TOP-001-3 (Transmission Operations)

12. NERC proposes Reliability Standard TOP-001-3 (Transmission Operations), which contains twenty requirements. The purpose of proposed Reliability Standard TOP-001-3 is to prevent instability, uncontrolled separation, or cascading outages that adversely affect the reliability of the interconnection, by ensuring prompt action to prevent or mitigate such occurrences. According to NERC, the proposed standard achieves this reliability goal by providing appropriate entities with the authority to take actions, or direct the actions of others, to maintain reliability during real-time operations. NERC explains that the standard includes real-time monitoring and real-time assessment

requirements to preserve reliability and ensure that applicable entities identify and address all SOL exceedances.

13. Requirements R1 and R2 require each transmission operator and balancing authority to explicitly and affirmatively act to address the reliability of its area through its own actions or by issuing operating instructions. In contrast, NERC notes that the obligation to act in currently effective Reliability Standard TOP-001-1a is implied, but not an explicit requirement. Requirements R3 and R4 together provide that each applicable entity must comply with each operating instruction issued by its transmission operator, unless doing so would violate safety, equipment, regulatory, or statutory requirements or the action cannot be physically implemented, and require an applicable entity to notify the transmission operator if it is unable to comply with the transmission operator's operating instruction. Similarly, Requirements R5 and R6 require the same actions of applicable entities with respect to an operating instruction issued by a balancing authority.

14. Requirement R7 requires each transmission operator to assist other transmission operators within its reliability coordinator area, and Requirement R8 requires a transmission operator to inform applicable entities of the transmission operator's actual or expected operations that result in, or could result in, an emergency.

15. Requirements R9, R16, and R17 address outage coordination of monitoring and control equipment. Requirement R9 provides that each balancing authority and transmission operator must notify its reliability coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or

more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Requirements R16 and R17 state that each transmission operator and balancing authority must provide its system operators with the authority to approve planned outages and maintenance.

16. Requirement R10 addresses transmission operator monitoring obligations to help ensure that transmission operators have the necessary situational awareness to maintain reliable operations. Requirement R10 provides that each transmission operator must take certain steps for determining SOL exceedances within its transmission operator area. NERC explains that Requirement R10 addresses the Commission's concerns that the TOP and IRO Reliability Standards, that were the subject of the Remand NOPR, did not have sufficient requirements for real-time monitoring. Requirement R11 is the equivalent of Requirement R10 for balancing authorities.

17. Requirement R12 provides that each transmission operator must not operate outside of any identified IROL for a continuous duration exceeding its associated IROL $T_{v.}$ NERC states that this requirement will provide consistency with the reliability coordinators requirements contained in currently-effective Reliability Standard IRO-009-1.[12] Requirement R13 provides that each transmission operator must ensure that a real-time assessment is performed at least once every 30 minutes. The revised definition of

[12] NERC defines T_v as "[t]he maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes."

"real-time assessment" includes additional specificity regarding various inputs for the assessment and how that information may be provided through third-party services, which may provide smaller entities an efficient method for compliance. Requirement R14 provides that each transmission operator must initiate its operating plan to mitigate a SOL exceedance identified as part of its real-time monitoring or real-time assessment.[13]

18. Requirement R15 provides that each transmission operator must inform its reliability coordinator of actions taken to return the system to within limits when a SOL has been exceeded. Requirement R18 provides that each transmission operator must operate to the most limiting parameter in instances where there is a difference in SOLs. Requirements R19 and R20 provide that each transmission operator and balancing authority must have data exchange capabilities with the entities from which it needs data in order to maintain reliability in its area.

19. In addition, NERC states that it removed the load-serving entity (LSE) function from proposed TOP-001-3, Requirements R3 through R6 due to the November 2014 NERC Board of Trustees action to remove the LSE as a functional entity from NERC's Rules of Procedure.[14] On May 12, 2015, NERC supplemented its filing with additional explanation for the removal of the LSE function.

[13] NERC Petition, Exhibit B at 5.

[14] NERC Petition, Exhibit K, Consideration of Comments January 7, 2015, at 2.

TOP-002-4 (Operations Planning)

20. Proposed Reliability Standard TOP-002-4 contains seven requirements relating to operations planning for transmission operators and balancing authorities. NERC explains that the proposed standard addresses next-day planning and provides for the necessary notifications and coordination between various functional entities. NERC adds that the revised definition of "operational planning analysis" specifies the scope and inputs required for next-day analyses. According to NERC, the proposed standard also improves coordination of next-day operations by requiring transmission operators and balancing authorities to provide operating plans to their reliability coordinators.

21. Proposed Requirements R1 through R3 and R6 apply to transmission operators, and proposed Requirements R4, R5, and R7 apply to balancing authorities. Requirement R1 requires each transmission operator to have an operational planning analysis that will allow it to assess whether its planned operations for the next day within its transmission operator area will exceed any of its SOLs. Requirement R2 requires each transmission operator to have operating plans for next-day operations to address potential SOL exceedances identified in the operational planning analysis performed pursuant to Requirement R1. Requirement R4 requires each balancing authority to have operating plans for the next day that address expected generation resource commitment and dispatch, interchange scheduling, demand patterns, and capacity and energy reserve requirements, including deliverability capability. Requirements R3 and R5 require each transmission operator and balancing authority, respectively, to notify the entities identified in their operating plan as to their roles in that plan. Requirements R6 and R7

require each transmission operator and balancing authority to provide its operating plan to its reliability coordinator.

TOP-003-3 (Operational Reliability Data)

22. Proposed Reliability Standard TOP-003-3 (Operational Reliability Data) establishes requirements for the provision of information and data needed by the transmission operator and balancing authority for reliable operations. The purpose of proposed Reliability Standard TOP-003-3 is to ensure that transmission operators and balancing authorities have the data needed to fulfill their operational and planning responsibilities. The proposed Reliability Standard consists of five Requirements, including requirements for balancing authorities and transmission operators to maintain and distribute to relevant entities data specifications needed to perform various analyses and assessments. The proposed Reliability Standard also requires entities receiving data specifications to respond according to mutually agreed upon parameters including format and security protocols.

23. Requirement R1 requires each transmission operator to maintain a documented specification for the data necessary, including non-bulk electric system and external network data, for it to perform its operational planning analysis, real-time monitoring, and real-time assessments. Requirement R2 requires each balancing authority to maintain a documented specification for the data necessary for it to perform its analysis functions and real-time monitoring. Requirements R3 and R4 require each transmission operator and balancing authority to distribute its data specification to the entities that have the necessary data. Requirement R5 requires each applicable entity receiving a data

specification pursuant to Requirement R3 or R4 to satisfy the obligations of the documented data specification.

24. In response to the Commission's concerns in the Remand NOPR with regard to the need for including external networks and sub-100 kV facilities in the operational planning analysis conducted by transmission operators, NERC explains that proposed Reliability Standard TOP-003-3 requires each applicable entity to develop a data specification that would cover its data needs for monitoring and analysis purposes, including non-bulk electric system data and external network data deemed necessary by the transmission operator to support its operational planning analyses, real-time monitoring, and real-time assessments. With respect to sub-100 kV facilities, NERC determined that any sub-100 kV elements that are necessary for reliable operation of the bulk electric system would be included as bulk electric system facilities through the exception process provided in Appendix 5C to the NERC Rules of Procedure. NERC explains that the exception process provides the means for transmission operators and reliability coordinators to include elements in the bulk electric system that are necessary for the reliable operation of the interconnected transmission system but were not identified in the bulk electric system definition. Accordingly, NERC concludes that it is not necessary to include non-bulk electric system monitoring in Reliability Standard TOP-001-3. In addition, NERC explains that proposed Reliability Standard TOP-001-3, Requirement R10 requires transmission operators to monitor bulk electric system facilities within their transmission operator area, and to obtain information deemed

necessary by the transmission operator about such bulk electric system facilities located outside of the transmission operator area when determining SOL exceedances.

25. NERC adds that when non-bulk electric facilities have no impact on the bulk electric system, but are needed for completing system models, the Commission-approved Reliability Standard FAC-001-2, Requirement R3 addresses the issue. This Reliability Standard requires the reliability coordinator to include in its methodology its entire reliability coordinator area and critical modeling details from other reliability coordinator areas that would affect the facility under study. In addition, the reliability coordinator must include details of system models used to determine SOLs.

Revisions to IRO Standards

26. The proposed IRO Reliability Standards, which complement the proposed TOP Standards, are designed to ensure that the bulk electric system is planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions. The proposed IRO Reliability Standards set forth the responsibility and authority of reliability coordinators to provide for reliable operations. NERC states that in the proposed IRO Reliability Standards reliability coordinators must continue to monitor SOLs in addition to their obligation in the currently effective Reliability Standards to monitor and analyze IROLs. These obligations require reliability coordinators to have the wide-area view necessary for situational awareness and provide them the ability to respond to system conditions that have the potential to negatively affect reliable operations.

IRO-001-4 (Reliability Coordination – Responsibilities)

27. Proposed Reliability Standard IRO-001-4 (Reliability Coordination – Responsibilities) contains requirements relating to the reliability coordinator's overall responsibility for reliable operation within the reliability coordinator area. Requirement R1 provides that each reliability coordinator must act to address the reliability of its reliability coordinator area through direct actions or by issuing operating instructions. Requirement R2 provides that each applicable entity must comply with its reliability coordinator's operating instructions unless compliance cannot be implemented or would violate safety, equipment, regulatory, or statutory requirements. Requirement R3 provides that applicable entities must inform the reliability coordinator if they are unable to perform an operating instruction issued by its reliability coordinator.

IRO-002-4 (Reliability Coordination – Monitoring and Analysis)

28. Proposed Reliability Standard IRO-002-4 (Reliability Coordination – Monitoring and Analysis) contains requirements relating to capabilities for monitoring and analysis of real-time operating data. The purpose of the proposed Reliability Standard is to provide system operators with the capabilities necessary to monitor and analyze data needed to perform reliability functions. Requirement R1 requires each reliability coordinator to have data exchange capabilities with its balancing authorities, transmission operators, and other entities as it deems necessary, for it to perform operational planning analyses, real-time monitoring, and real-time assessments. Requirement R2 provides that each reliability coordinator must provide its system operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring, and

analysis capabilities. Requirement R3 provides that each reliability coordinator must monitor facilities, the status of special protection systems and non-bulk electric system facilities identified as necessary within its reliability coordinator area and neighboring reliability coordinator areas, to identify any SOL or IROL exceedances. Requirement R4 provides that each reliability coordinator must have monitoring systems that provide information used by the reliability coordinator's operating personnel, with particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments)

29. Proposed Reliability Standard IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments) contains requirements for reliability coordinators to conduct next-day analyses and assessments of operating conditions in real-time to help prevent instability, uncontrolled separation, or cascading. NERC states that the proposed definitions of operational planning analysis and real-time assessment are integral components of proposed Reliability Standard IRO-008-2 because they specify the scope and inputs for next-day analysis and real-time assessments of operating conditions in real-time. Furthermore, NERC states that proposed Reliability Standard IRO-008-2 enhances next-day operations planning by specifying requirements for coordination of the reliability coordinator's operating plan to address potential SOL and IROL exceedances.

30. Requirement R1 provides that each reliability coordinator must perform an operational planning analysis that will allow it to assess whether the planned operations

for the next day will exceed SOLs and IROLs. Requirement R2 requires each reliability coordinator to have a coordinated operating plan for next-day operations to address potential SOL and IROL exceedances identified as a result of its operating planning analysis. Requirement R3 provides that each reliability coordinator must notify impacted entities identified in its operating plan as to their role in the plan. Requirement R4 states that each reliability coordinator must ensure that a real-time assessment is performed at least once every 30 minutes. Requirement R5 provides that each reliability coordinator must notify impacted transmission operators and balancing authorities within its reliability coordinator area and other impacted reliability coordinators when a real-time assessment indicates an actual or expected condition that results in, or could result in, a SOL or IROL exceedance. Further, Requirement R6 provides that each reliability coordinator must notify impacted entities when a SOL or IROL exceedance has been prevented or mitigated.

IRO-010-2 (Reliability Coordinator Data Specification and Collection)

31. Proposed Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection) provides a mechanism for a reliability coordinator to obtain the information and data it needs for reliable operations and to help prevent instability, uncontrolled separation, or cascading outages. According to NERC, proposed Reliability Standard IRO-010-2 reflects recommendations from the 2011 Southwest Outage Blackout Report, including more clearly identifying necessary data and information to be included in a reliability coordinator's data specification. Requirement R1 provides that the reliability coordinator must maintain a documented specification for the data,

including non-bulk electric system and external network data, necessary for it to perform its operational planning analyses, real-time monitoring, and real-time assessments. Requirement R2 provides that the reliability coordinator must distribute its data specification to entities that have the required data. Requirement R3 provides that applicable entities receiving a data specification must satisfy the obligations of the documented specification using a mutually-agreeable format, process for resolving data conflicts, and security protocol.

IRO-014-3 (Coordination Among Reliability Coordinators)

32. Proposed Reliability Standard IRO-014-3 (Coordination among Reliability Coordinators) contains requirements for coordination for interconnected operations at the reliability coordinator level. The purpose of the proposed Reliability Standard is to ensure that each reliability coordinator's operations are coordinated such that they will not adversely affect other reliability coordinator areas and to preserve the reliability benefits of interconnected operations. Requirement R1 requires each reliability coordinator to have and implement operating procedures, processes, or plans for activities that require notification or coordination of actions that may affect adjacent reliability coordinator areas. Requirement R2 requires each reliability coordinator to maintain its operating procedures, processes, or plans through annual reviews and updates, with no more than 15 months passing between reviews. Requirement R3 requires each reliability coordinator to notify other impacted reliability coordinators upon identification of an expected or actual emergency. Requirement R4 specifies that, if the reliability coordinators disagree on the existence of an emergency, each must operate as though an

emergency exists. Requirement R5 states that a reliability coordinator that identifies an emergency must develop an action plan to resolve the emergency, and Requirement R6 requires impacted reliability coordinators to implement the action plan. Under Requirement R7, a reliability coordinator must assist another reliability coordinator if the requesting reliability coordinator has implemented its emergency procedures.

IRO-017-1 (Outage Coordination)

33. NERC states that proposed Reliability Standard IRO-017-1 (Outage Coordination) is a new Reliability Standard designed to ensure that outages are properly coordinated in the operations planning time horizon and near-term transmission planning horizon. According to NERC, the requirements in the proposed Reliability Standard, which span both time horizons, provide the necessary requirements for effective coordination of planned outages to support reliable operations.

34. NERC notes that in the Remand NOPR the Commission identified coordination of outages as a critical reliability function that should be performed by the reliability coordinator that was not adequately addressed. NERC explains that proposed Reliability Standard IRO-017-1 addresses the Commission's Remand NOPR concerns by requiring each reliability coordinator to develop, implement and maintain an outage coordination process for generation and transmission outages. NERC also explains that each transmission operator and balancing authority would then be required to perform the functions specified in its reliability coordinator's process. Further, NERC states that each planning coordinator and transmission planner will provide its planning assessment to relevant reliability coordinators and work together to solve any issues or conflicts with

planned outages among the applicable entities. Additionally, NERC states that proposed Reliability Standard IRO-014-3, Requirement R1, Part 1.4 requires reliability coordinators to coordinate with adjacent reliability coordinators the exchange of planned and unplanned outage information to support operational planning analyses and real-time assessments in their operating procedures, processes, or plans.

35. Proposed Reliability Standard IRO-017-1 has four requirements. Requirement R1 provides that each reliability coordinator must develop, implement, and maintain an outage coordination process for generation and transmission outages. Requirement R2 provides that each transmission operator and balancing authority must perform the functions specified in its reliability coordinator's outage coordination process. Requirement R3 provides that each planning coordinator and transmission planner must provide its planning assessment to impacted reliability coordinators. Requirement R4 requires each planning coordinator and transmission planner to jointly develop solutions with its respective reliability coordinators for identified issues or conflicts with planned outages in its planning assessment for the near-term transmission planning horizon.

Definitions

36. NERC also proposes revised definitions for "operational planning analysis" and "real-time assessment."[15] NERC contends that the proposed definitions provide

[15] The proposed definition of operational planning analysis is "[a]n evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange;

(continued ...)

significant additional detail compared to the currently effective definitions to enhance the consistency and the reliability benefit of operational planning analysis and real-time assessments.[16] NERC states that the additional specificity reflected in the proposed definitions addresses concerns raised in the Remand NOPR and includes several inputs that were identified as recommendations in the 2011 Southwest Outage Blackout Report, which, in turn, will enhance situational awareness.

37. The proposed NERC Glossary term "Operating Instruction" defines the scope of commands that are covered by the proposed TOP and IRO Reliability Standards. NERC explains that the revisions in the proposed definitions are intended to ensure that operational planning analyses and real-time assessments contain sufficient details to result in an appropriate level of situational awareness for next-day planning and real-time operations, respectively.

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known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"

[16] The proposed definition of real-time assessment is "[a]n evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"

Implementation Plan

38. NERC proposes that, for all standards except proposed Reliability Standards TOP-003-3 and IRO-010-2, the effective date will be the first day of the first calendar quarter twelve months after Commission approval. The twelve month implementation period for all of the standards except TOP-003-3 and IRO-010-2 is intended to allow time for entities to update processes and train operators on the revised requirements. All of the Requirements in proposed TOP-003-3 and IRO-010-2 except TOP-003-3, Requirements R5 and IRO-010-2, Requirement R3 would become effective three months earlier, in order to provide recipients of data requests from their reliability coordinators, transmission operators, and/or balancing authorities time to respond to the requests for data.

39. According to NERC's implementation plan, for proposed TOP-003-3, all requirements except Requirement R5 will become effective on the first day of the first calendar quarter nine months after the date that the standard is approved. For proposed IRO-010-2, Requirements R1 and R2 would become effective on the first day of the first calendar quarter that is nine months after the date that the standard is approved. Requirement R3 would become effective on the first day of the first calendar quarter twelve months after the date that the standard is approved. NERC states that the reason for the difference in effective dates for proposed TOP-003-3 and IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests.

II. Discussion

40. Pursuant to section 215(d) of the FPA, we propose to approve NERC's proposed revisions to the TOP and IRO Reliability Standards as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We believe that NERC's approach of consolidating requirements and removing redundancies generally has merit and is consistent with Commission policy promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently effective requirements or have little reliability benefit.[17]

41. We agree with NERC that the proposed TOP and IRO Reliability Standards would improve reliability by defining an appropriate division of responsibilities between reliability coordinators and transmission operators.[18] Specifically, NERC states that the proposed TOP Reliability Standards will be improved by eliminating multiple TOP standards, resulting in a more concise set of standards. Thus, we believe that NERC's TOP proposal would reduce redundancy and more clearly delineate responsibilities between applicable entities. In addition, we believe that the proposed Reliability Standards provide a comprehensive framework as well as important improvements to ensure that the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning. We believe that

[17] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

[18] *See, e.g.*, Order No. 748, 134 FERC ¶ 61,213, at PP 39-40.

the proposed TOP and IRO Reliability Standards address the coordinated efforts to plan and reliably operate the bulk electric system under both normal and abnormal conditions.

42. For these reasons, we propose to approve NERC's revisions to the TOP and IRO Reliability Standards. We also discuss below: (A) concerns raised in the Remand NOPR plus possible inconsistencies of identifying IROLs; (B) other reliability issues including (1) monitoring of non-bulk electric system facilities; (2) removal of the load-serving entity function from proposed Reliability Standard TOP-001-3; and (3) data exchange capabilities.

A. Remand NOPR Issues

1. Operational Responsibilities and Actions of SOLs and IROLs

43. We propose to find that NERC has adequately addressed the concerns raised by the Commission in the Remand NOPR with respect to the treatment of SOLs in the proposed TOP Reliability Standards. In the Remand NOPR, the Commission expressed concern that the proposed TOP standards did not have a requirement "for transmission operators to plan and operate within all SOLs. Without a requirement to plan and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area."[19] The Commission noted that "non-IROL SOLs that appear to be excluded from

[19] Remand NOPR, 145 FERC ¶ 61,158 at P 42.

the proposed standard are non-IROL SOLs that are in a transmission operator's area that impact another transmission operator's area or more than one transmission operator's area."[20]

44. The Commission believes that the proposed TOP Reliability Standards address the Commission's Remand NOPR concerns by requiring transmission operators to plan and operate within all SOLs, and to monitor and assess SOL conditions within and outside a transmission operator's area. Specifically, proposed Reliability Standard TOP-001-3, Requirement R14 requires each transmission operator to initiate its operating plan to mitigate a SOL exceedance identified as part of its real-time monitoring or real-time assessment. Proposed Reliability Standard TOP-001-3, Requirement R10 requires each transmission operator to monitor facilities within its transmission operator area as well as certain facilities outside of its transmission operator area to determine SOL exceedances within its transmission operator area during the real-time operations time horizon. In addition, proposed Reliability Standard TOP-001-3, Requirement R15 requires that each transmission operator inform its reliability coordinator of actions taken to resolve a SOL exceedance.[21] To address the concerns of operational planning, proposed Reliability Standard TOP-002-4, Requirement R1 requires each transmission operator to have an operational planning analysis to assess whether its next-day planned operations will

[20] *Id*. P 51.

[21] NERC Petition at 24-25.

exceed any of its SOLs within its area, and Requirement R2 requires the transmission operator to have a next-day operating plan(s) to address any potential SOLs exceedances identified in its operational planning analysis.[22]

45. Further, proposed Reliability Standard IRO-008-2, Requirements R1, R2, R3, R5, and R6 require reliability coordinators to plan and operate within SOLs and IROLs, which we believe work in tandem with the proposed TOP Standards and address the Commission's concern that the previously-proposed Reliability Standards limited "non-IROL SOLs" to only those internally identified by the transmission operator. Specific to operational planning, proposed Reliability Standard IRO-008-2, Requirement R1 requires the reliability coordinator to have an operational planning analysis to assess whether its next-day planned operations will exceed SOLs and IROLs within its wide area, and Requirement R2 requires the reliability coordinator to have a coordinated next-day operating plan(s) to address potential SOLs and IROLs exceedances identified in its operational planning analysis while considering the next-day operating plan(s) provided by its transmission operators and balancing authorities.[23] Requirement R3 requires the reliability coordinator to notify impacted entities identified in its operating plan cited in Requirement R2 as to their role in such plan(s). The Commission believes that the consideration of the transmission operators' and balancing authorities' operating plans by

[22] NERC Petition at 27.

[23] NERC Petition at 52.

the reliability coordinator in its own operating plan provides the necessary situational awareness of all SOLs, internal and external to the transmission operator or balancing authority.

46. In the Remand NOPR, the Commission raised the concern that the then-proposed version of the TOP/IRO Standards did not consider the possibility that additional SOLs could develop or occur in the same-day or real-time operational time horizon, and therefore would pose an operational risk to the interconnected transmission network.[24] To address this concern, Reliability Standard IRO-008-2, Requirement R5 requires each reliability coordinator to notify impacted transmission operators and balancing authorities within its reliability coordinator area and other impacted reliability coordinators when results of a real-time assessment indicate actual or expected conditions that could result in SOL or IROL exceedances, and Requirement R6 requires reliability coordinator notification to impacted transmission operators, balancing authorities and other impacted reliability coordinators when any SOLs or IROLs have been prevented or mitigated.[25]

47. Likewise, based on NERC's explanation, we believe that the proposed Reliability Standards in the immediate proceeding are designed to improve system performance by giving reliability coordinators the authority to direct actions to prevent or mitigate instances of exceeding IROLs. This delineation of responsibilities between reliability

[24] Remand NOPR, 145 FERC ¶ 61,158 at P 55.

[25] NERC Petition at 32.

coordinators and transmission operators is appropriate because the primary decision-making authority for mitigating IROL exceedances is assigned to reliability coordinators while transmission operators have the primary responsibility for mitigating SOL exceedances.[26] To further support the reliability coordinator's primary responsibility for IROLs to prevent instability, uncontrolled separation, or cascading, proposed Reliability Standard TOP-001-3, Requirement R12 requires that a transmission operator must not operate outside of any identified IROLs for a continuous duration exceeding its associated IROL T_V.[27]

48. In addition, NERC explains that the proposed Reliability Standard IRO-014-3 contains requirements for coordination of interconnection operations at the reliability coordinator level and ensures that each reliability coordinator's operations are coordinated such that they will not adversely affect other reliability coordinators' areas.[28] Proposed Reliability Standard IRO-014-3 requires the reliability coordinator to have and implement operating procedures, processes, or plans for activities that require notification or coordination of actions that may affect adjacent reliability coordinators' areas.

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[26] *See* Remand NOPR, 145 FERC ¶ 61,158 at P 85. Further, currently-effective Reliability Standard IRO-009-1, Requirement R4 states that "[w]hen actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's T_V."

[27] NERC Petition at 25.

[28] NERC Petition at 33.

49. Furthermore, the Commission believes the revised definitions of operational planning analysis and real-time assessment are critical components of the proposed TOP and IRO Reliability Standards and, together with the definitions of SOLs, IROLs and operating plans, work to ensure that reliability coordinators, transmission operators and balancing authorities plan and operate the bulk electric system within all SOLs and IROLs to prevent instability, uncontrolled separation, or cascading. In addition, the revised definitions of operational planning analysis and real-time assessment address other concerns raised in the Remand NOPR as well as multiple recommendations in the 2011 Southwest Outage Blackout Report.[29] For example, the definition of operational planning analysis is used in proposed Reliability Standards TOP-002-4, TOP-003-3, IRO-002-4, IRO-008-2, IRO-010-2, and IRO-014-3 to ensure a consistent approach to operations planning for the reliability coordinators, transmission operators and balancing authorities.[30] Further, the proposed revised operational planning analysis definition adds additional detail and clarity, including the evaluation of pre- and post-contingency conditions as well as the evaluation of multiple applicable inputs that are absent in the currently-effective definition.

50. Likewise, the definition of real-time assessment is used in the following proposed Reliability Standards: TOP-001-3; TOP-003-3; IRO-002-4; IRO-008-2; IRO-010-2; and

[29] NERC Petition at 17-18.

[30] NERC Petition at 19.

IRO-014-3 to ensure a consistent approach to the real-time operation of the Bulk Power System for the reliability coordinators, transmission operators and balancing authorities.[31] The proposed revised real-time assessment definition is the same type of evaluation as the operational planning analysis with the exception that real-time assessment uses real-time data to assess existing conditions and operational planning analysis uses projected system conditions to assess anticipated system conditions.

51. The Commission does note, however, that in Exhibit E (SOL White Paper) of NERC's petition, NERC states that with regard to the SOL concept, the SOL White Paper brings "clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances."[32] The Commission further notes that IROLs, as defined by NERC, are a subset of SOLs that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system.[33] The Commission agrees with NERC that clarity and consistency are important with respect to establishing and implementing operating plans to mitigate SOL and IROL exceedances. However, the Commission notes that in

[31] NERC Petition at 18.

[32] NERC Petition, Exhibit E, "White Paper on System Operating Limit Definition and Exceedance Clarification" at 1.

[33] NERC Glossary of Terms defines Interconnection Reliability Operating Limit as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

its 2015 State of Reliability report, NERC states that the Western Interconnection reliability coordinator definition of an IROL has additional criteria that may not exist in other reliability coordinator areas.[34] Based on this information, it is unclear whether NERC regions apply a consistent approach to identifying IROLs. Accordingly, the Commission seeks comment on (1) identification of all regional differences or variances in the formulation of IROLs, (2) the potential reliability impacts of such differences or variations, and (3) the value of providing a uniform approach or methodology to defining and identifying IROLs.

2. Outage Coordination

52. We believe, too, that NERC has addressed the concerns raised in the Remand NOPR with respect to the IRO standards regarding planned outage coordination. In the Remand NOPR, the Commission expressed concern with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a (subjects of the proposed remand and now withdrawn by NERC) did not require the coordination of

[34] NERC 2015 State of Reliability report at 44, available at www.nerc.com. *See also* WECC Reliability Coordination System Operating Limits Methodology for the Operations Horizon, Rev. 7.0 (effective March 3, 2014) at 18 (stating that "SOLs qualify as IROLs when … studies indicate that instability, Cascading, or uncontrolled separation may occur resulting in uncontrolled interruption of load equal to or greater than 1000 MW"), available at https://www.wecc.biz/Reliability/PhaseII%20WECC%20RC%20SOL%20Methodology%20FINAL.pdf.

outages, noting that outage coordination is a critical reliability function that should be performed by the reliability coordinator.[35]

53. With respect to proposed Reliability Standard IRO-017-1, submitted by NERC for approval in the immediate proceeding, Requirement R1 requires each reliability coordinator to develop, implement and maintain an outage coordination process for generation and transmission outages within its reliability coordinator area. Under Requirement R2, each transmission operator and balancing authority, in turn, would perform the functions specified in its reliability coordinator's outage coordination process. Further, Requirement R3 requires each planning coordinator and transmission planner to provide its planning assessment to the relevant reliability coordinators and to work together to solve any issues or conflicts with planned outages among the applicable entities under Requirement R4. Additionally, proposed Reliability Standard IRO-014-3, Requirement R1, Part 1.4 requires reliability coordinators to include the exchange of planned and unplanned outage information to support operational planning analyses and real-time assessments in the operating procedures, processes, and plans for activities that require coordination with adjacent reliability coordinators. Further, the proposed revised definitions of operational planning analysis and real-time assessments require that these evaluations of system conditions include transmission and generation outages. We

[35] Remand NOPR, 145 FERC ¶ 61,158 at P 90.

believe that these proposed standards and revised definitions adequately address our concerns with respect to outage coordination as outlined in the Remand NOPR.

B. Other Reliability Issues

54. While proposing to approve the TOP and IRO Reliability Standards, the Commission seeks clarifying comments addressing three additional issues: (1) monitoring of non-bulk electric system facilities; (2) removal of the load-serving entity as an applicable entity for proposed Reliability Standard TOP-001-3; and (3) data exchange capabilities. Based on comments and information received on these issues, the Commission may issue directives as appropriate.

1. Monitoring of Non-Bulk Electric System Facilities

NERC Petition

55. NERC explains how the proposed Reliability Standards address the recommendations in the 2011 Southwest Outage Blackout Report, in particular with respect to Finding 17 concerning the impact of sub-100 kV facilities on the reliability of the interconnected transmission network. Finding 17 states:

> WECC RC and affected TOPs and BAs do not consistently recognize the adverse impact sub-100 kV facilities can have on BPS reliability. As a result, sub-100 kV facilities might not be designated as part of the BES, which can leave entities unable to address the reliability impact they can have in the planning and operations time horizons. If, prior to September 8, 2011, certain sub-100 kV facilities had been designated as part of the BES and, as a result, were incorporated into the TOPs' and RC's planning and operations studies, or otherwise had been incorporated into these studies, cascading outages may have been avoided on the day of the event.

Recommendation 17 states:

> WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in [real-time contingency analysis] systems.

NERC states that proposed Reliability Standard IRO-002-4, Requirement R3 addresses monitoring of non-bulk electric system facilities by requiring each reliability coordinator to monitor facilities and necessary non-bulk electric system facilities in order to identify SOL and IROL exceedances within its reliability coordinator area.[36] In addition, NERC states that proposed Reliability Standards IRO-010-2, Requirement R1.1 and TOP-003-3, Requirement R1.1 address non-bulk electric system data by specifically requiring reliability coordinators and transmission operators to incorporate any non-bulk-electric system data as deemed necessary into their operational planning analyses, real-time monitoring, and real-time assessments.[37]

56. However, NERC explains that the standard drafting team concluded it is unnecessary to include non-bulk electric system monitoring in proposed Reliability Standard TOP-001-3, Requirement R10 for the transmission operator, in a similar fashion as proposed Reliability Standard IRO-002-4, Requirement R3 for the reliability

[36] NERC Petition at 61.

[37] *Id.* at 40.

coordinator. Instead, the standard drafting team determined that any non-bulk electric system facility elements that are necessary for reliable operation of the bulk electric system would be included in the bulk electric system through the exception process provided in Appendix 5C to the NERC Rules of Procedure. NERC states that the exception process provides the means for transmission operators and reliability coordinators to include elements in the bulk electric system that are necessary for the reliable operation of the interconnected transmission system but not identified in the bulk electric system definition.[38]

Commission Proposal

57. We propose to find that NERC has adequately addressed the 2011 Southwest Outage Blackout Report recommendation in connection with sub-100 kV facilities for proposed Reliability Standards IRO-002-4, Requirement R3, IRO-010-2, Requirement R1.1 and TOP-003-3, Requirement R1.1. In doing so, we rely primarily on the proposed responsibility of the reliability coordinator to monitor such facilities to the extent necessary.

58. However, the transmission operator may have a more granular perspective than the reliability coordinator of its necessary non-bulk electric system facilities to monitor in order to identify SOL and IROL exceedances, and it is not clear whether or how the transmission operator would communicate any insight it may have to the reliability

[38] *Id.* at 47-48.

coordinator to ensure monitoring of all necessary facilities. Thus, the Commission seeks comment on how NERC will ensure that the reliability coordinator will receive information from the transmission operator regarding which non-bulk electric system facilities should be monitored. Further, as stated above, Recommendation 17 states "…to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or *otherwise incorporated into planning and operations studies and actively monitored and alarmed in [real-time contingency analysis] systems*." (emphasis added.) Including such non-bulk electric system facilities in the definition of bulk electric system through the Rules of Procedure exception process could be an option to address any potential gaps for monitoring facilities. However, there may be potential efficiencies gained by using a more expedited method to include non-bulk electric system that requires monitoring. Thus, the Commission seeks comments on whether the exception process should be used exclusively in all cases.

59. Alternatively, we seek comment regarding whether this concern should be addressed through a review process of the transmission operators' systems to determine if there are important non-bulk-electric system facilities that require monitoring. For example, Commission staff could work with NERC, Regional Entities and applicable entities to review their system modeling and perform an analysis to identify non-bulk electric system facilities that need monitoring. Accordingly, we seek comment from NERC and other interested persons on these alternatives.

2. Removal of Load-Serving Entity Function from TOP-001-3

NERC Petition

60. Proposed Reliability Standard TOP-001-3, Requirement R3 requires that each balancing authority, generator operator and distribution provider shall comply with each operating instruction issued by its transmission operator, and proposed Reliability Standard TOP-001-3, Requirement R4 requires that each balancing authority, generator operator and distribution provider inform its transmission operator of its inability to comply with an operating instruction. Proposed Reliability Standard TOP-001-3, Requirement R5 requires that each transmission operator, generator operator and distribution provider shall comply with each operating instruction issued by its balancing authority, and proposed Reliability Standard TOP-001-3, Requirement R6 requires that each transmission operator, generator operator and distribution provider inform its balancing authority of its inability to comply with an operating instruction.[39]

61. In its petition, NERC states that, during the standard drafting process, the load-serving entity function was removed from proposed Reliability Standard TOP-001-3, Requirements R3 through R6. NERC explains that the removal of the load-serving entity as an applicable entity was based on the November 2014 NERC Board of Trustees action to remove load-serving entity as a functional entity from NERC's Rules of Procedure.[40]

[39] NERC Petition at 22-23.

[40] NERC Petition, Exhibit K, Consideration of Comments January 7, 2015, at 2.

Since that time, the Commission has issued an order in Docket No. RR15-4-000 that denied, without prejudice, NERC's proposal to remove the load-serving entity as a functional entity under NERC's Risk Based Registration petition and directed NERC to submit a compliance filing to address this issue.[41]

62. On May 12, 2015, NERC supplemented its initial petition with additional explanation for the removal of the load-serving entity function from proposed Reliability Standard TOP-001-3. NERC explains that the proposed standard gives transmission operators and balancing authorities the authority to direct the actions of certain other functional entities by issuing an operating instruction to maintain reliability during real-time operations. According to NERC, load-serving entities are not included in the list of entities that must comply with a transmission operator's or balancing authority's operating instructions. NERC contends that the exclusion is justified because none of the functions performed by load-serving entities, as described in the NERC Functional Model, necessitate that load-serving entities be subject to a requirement to comply with such operating instructions to ensure that a transmission operator or balancing authority can maintain reliability.[42] NERC adds that a load-serving entity does not own or operate bulk electric system facilities or equipment or the facilities or equipment used to serve end-use customers and its NERC Functional Model tasks are limited in scope. As

[41] *North American Electric Reliability Corp.*, 150 FERC ¶ 61,213 (2015).

[42] NERC Supplemental Filing at 6.

indicated by the NERC Functional Model, the load-serving entity does not play a role in shedding load in real-time.

63. NERC also explains in its supplemental filing that the standard drafting team did not identify any circumstances under which a transmission operator or balancing authority would need to issue an operating instruction to a load-serving entity to prevent instability, uncontrolled separation, or cascading outages. NERC contends that, with respect to the load-serving entity's role as a provider of information to other functional entities, that role is primarily carried out ahead of real-time and would not be the subject of an operating instruction. Additionally, NERC states that the load-serving entity's real-time role with respect to voluntary load curtailment does not necessitate requiring load-serving entities to comply with operating instructions issued by a transmission operator or balancing authority. In order to maintain reliability in their areas and prevent instability, uncontrolled separation, or cascading outages, there may be circumstances under which transmission operators and balancing authorities need to shed load. NERC states that such action is implemented in real-time to address imminent or existing reliability issues such as an exceedance of an IROL or SOL, or a voltage problem. According to NERC, due to the urgent nature of these circumstances, the reliability coordinator, balancing authority, or transmission operator may issue operating instructions directly to the

distribution provider for physical implementation of load shedding (except when this can be accomplished directly by the transmission operator).[43]

Commission Proposal

64. NERC proposes the removal of the load-serving entity function from proposed Reliability Standard, TOP-001-3, Requirements R3 through R6, as a recipient of an operating instruction from a transmission operator or balancing authority. However, the Commission notes that the issuance and compliance of operating instructions under proposed Reliability Standard TOP-001-3 is not limited to the real-time operations time horizon only.[44]

65. Further, if a transmission operator or balancing authority would issue an operating instruction to a load-serving entity such as to carry out interruptible load curtailments, it is not clear what entity would respond to this operating instruction if the load-serving entity is removed from proposed TOP-001-3, Requirements R3 through R6.[45]

[43] NERC Supplemental Filing at 9.

[44] NERC TOP/IRO Petition, Exhibit A includes the following time horizons for proposed Reliability Standard TOP-001-3, Requirements R3 through R6: "*[Time Horizon: Same-Day Operations, Real-Time Operations]*."

[45] NERC Glossary of Terms defines Interruptible Load as the "[d]emand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment."

66. The Commission notes that NERC is required to make a compliance filing in July 2015 in Docket No. RR15-4-000. The Commission's decision on that filing will guide any action in this proceeding.

3. Data Exchange Capabilities

NERC Petition

67. In Order No. 808, the Commission approved Reliability Standards COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols).[46] In Order No. 808, the Commission explained that it had raised concerns in the underlying NOPR proposing to approve these COM Reliability Standards (COM NOPR) whether COM-001-2 addresses "facilities that directly exchange or transfer data."[47] In response to the COM NOPR, NERC and other commenters clarified that Reliability Standard COM-001-2, which covers communications capability requirements, is not intended to address data exchanges or transfers.[48] As the Commission noted in Order No. 808, NERC maintained that Reliability Standard COM-001-2 need not include requirements regarding data exchange capability, "because such capability is covered under other existing or proposed standards."[49] The Commission did not make any determinations

[46] *Communications Reliability Standards*, Order No. 808, 151 FERC ¶ 61,039 (2015).

[47] Order No. 808, 151 FERC ¶ 61,039 at P 54, *quoting Communications Reliability Standards, Notice of Proposed Rulemaking*, 148 FERC ¶ 61,210, at P 33 (2014).

[48] *Id.* P 48.

regarding facilities used for data exchange capability in Order No. 808 and, based on NERC's explanation in its supplemental filing, the Commission stated that it would address these issues in this TOP and IRO rulemaking proceeding.[50]

68. In general, it appears that facilities for data exchange capabilities are addressed in NERC's proposal. For example, proposed Reliability Standard TOP-001-3, Requirements R19 and R20 require some form of "data exchange capabilities" for the transmission operator and balancing authority, respectively. Similarly, proposed Reliability Standard IRO-002-4, Requirement R1 requires some form of "data exchange capabilities" for the reliability coordinator. However, we seek additional explanation from NERC regarding how it addresses data exchange capabilities in the TOP and IRO Reliability Standards in the following areas: (a) redundancy and diverse routing; and (b) testing of the alternate or less frequently used data exchange capability.

(i) Redundancy and Diverse Routing of Data Exchange Capabilities

Background

69. The terms "redundant" and "diverse routing" of data exchange capabilities appear in Reliability Standard COM-001-1, where the reliability coordinator, transmission operator and balancing authority are required to have telecommunication facilities that

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[49] *Id.* *See also* NERC's Supplemental Comments in Response to Notice of Proposed Rulemaking, *Communications Reliability Standards*, Docket No. RM14-13-000 at 3.

[50] Order No. 808, 151 FERC ¶ 61,039 at P 54.

are "redundant" and "diversely routed" to maintain Bulk-Power System reliability.[51] NERC added two definitions (Interpersonal Communication and Alternative Interpersonal Communication) to Reliability Standard COM-001-2 that addressed redundant and diverse routing of communications between persons and proposed to eliminate the need to use phrases such as "redundant and diversely routed" that it described as ambiguous.[52] With respect to the data exchange capabilities, NERC stated that several proposed or existing standards "provided the necessary mandatory Requirements to ensure proper data exchange is occurring."[53] NERC also asserted that four proposed IRO and TOP standards "include specific coverage related to data exchange," and "collectively require data exchange capability" for reliability coordinators, transmission operators, balancing authorities, generator operators, and distribution providers.[54]

[51] COM-001-1.1 Standard, Requirement R1 requires that "[e]ach Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:" and R1.4 requires that "[w]here applicable, these facilities shall be redundant and diversely routed."

[52] NERC COM Petition at 16.

[53] NERC COM Petition at 16.

[54] NERC Supp. COM Comments at 3. NERC identified these same four standards in its Initial Comments, but provides a more detailed discussion of the proposed standards and their status in its Supplemental Comments.

70. In Order No. 808, the Commission approved NERC's definition of the terms Interpersonal Communication and Alternative Interpersonal Communication. NERC defines Interpersonal Communication as "[a]ny medium that allows two or more individuals to interact, consult, or exchange information." NERC defines Alternative Interpersonal Communication as "[a]ny Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."[55] Reliability Standard COM-001-2, Requirements R1 through R6 require that reliability coordinators, transmission operators, and balancing authorities have Interpersonal Communication capabilities and Alternative Interpersonal Communication capabilities in place with other defined entities (*e.g.*, other interconnected transmission operators). In its COM Petition, NERC maintained that the defined terms make clear that an entity's communication capability must be redundant and that each of the capabilities must not utilize the same medium, while eliminating the need to use ambiguous phrases such as "redundant and diversely routed" (as used in the prior version of the standard governing communications capability).[56]

71. As noted above, NERC indicated in its response to the COM NOPR that Reliability Standard COM-001-2 need not include requirements regarding data exchange

[55] Order No. 808, 151 FERC ¶ 61,039, at P 45 n.54.

[56] May 14, 2014, NERC COM Petition, Docket No. RM14-13-000 at 15-16.

capability because such capability is or would be covered by other existing or proposed standards. Specifically, NERC explained that data exchange is addressed by the currently enforceable Reliability Standards IRO-010-1a and IRO-014-1. In addition, NERC stated that data exchange transfer capabilities are directly addressed in proposed Reliability Standard TOP-001-3, as well as in proposed Reliability Standard IRO-002-4, Requirement R1. NERC also stated that the data itself is covered in proposed Reliability Standard IRO-010-2 and proposed Reliability Standard TOP-003-3.[57]

NERC Petition

72. In the petition in this proceeding, NERC states that in proposed Reliability Standard TOP-001-3, "Requirements R19 and R20 provide that each Transmission Operator (Requirement R19) and Balancing Authority (Requirement R20) must have data exchange capabilities with the entities from which it needs data in order to maintain reliability in its area."[58] NERC states that Requirements R19 and R20 are consistent with proposed Reliability Standard IRO-002-4, Requirement R1, which provides that each reliability coordinator must have data exchange capabilities with its balancing authorities, transmission operators, and other entities it deems necessary. Requirements R19 and R20 state:

[57] NERC COM Supplemental Comments at 3.

[58] NERC Petition at 26.

> R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.
>
> R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

Reliability Standard IRO-002-4 Requirement R1 states:

> R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

In addition, NERC states that IRO-002-4, Requirement R4 requires "each Reliability Coordinator must have monitoring systems…over a redundant infrastructure."[59]

Commission Proposal

73. The Commission agrees that proposed Reliability Standard TOP-001-3, Requirements R19 and R20 require some form of "data exchange capabilities" for the transmission operator and balancing authority, respectively, and that proposed Reliability Standard TOP-003-3 addresses the operational data itself needed by the transmission operator and balancing authority. In addition, the Commission agrees that Reliability Standard IRO-002-4, Requirement R1 requires "data exchange capabilities" for the reliability coordinator and that proposed Reliability Standard IRO-010-2 addresses the operational data needed by the reliability coordinator. Further, the Commission agrees

[59] *Id.* at 31.

that proposed Reliability Standard IRO-002-4 Requirement R4 requires a redundant infrastructure for system monitoring. However, it is not clear whether redundancy and diverse routing of data exchange capabilities (or an equally effective alternative that eliminates the ambiguity of "redundancy" and "diversely routed") are adequately addressed in proposed Reliability Standards TOP-001-3 and IRO-002-4 for the reliability coordinator, transmission operator, and balancing authority.

74. Unlike the approach taken with COM-001-2, which requires redundancy and use of a diverse medium through the definitions of Interpersonal Communication and Alternative Interpersonal Communication, proposed Reliability Standards TOP-001-3 and IRO-002-4 do not appear to address redundancy and diverse routing of data exchange capabilities. While Reliability Standard IRO-002-4, Requirement R4 requires reliability coordinators to have a redundant infrastructure for system monitoring, it is not clear whether this requirement addresses redundancy and diverse routing of other forms of data exchange capabilities. For example, a redundant infrastructure used for system monitoring could be a subset of the total data exchange capabilities used by reliability coordinators and not include redundant infrastructure for capabilities such as control of equipment or real-time assessments. The Commission seeks explanation or clarification from NERC whether and how the proposed Reliability Standards in the immediate proceeding address redundancy and diverse routing or an equally effective alternative to redundancy and diverse routing. Further, if NERC or others believe that redundancy and diverse routing are not addressed, we seek comment on whether there are associated

reliability risks of the interconnected transmission network for any failure of data exchange capabilities that are not redundant and diversely routed.

(ii) Testing of the Alternate or Less Frequently Used Data Exchange Capability

NERC Petition

75. Reliability Standard COM-001-2, Requirement R9 (approved in Order No. 808) requires each reliability coordinator, transmission operator and balancing authority to test its Alternative Interpersonal Communication capability at least once each calendar month and to initiate action to repair or designate a replacement Alternative Interpersonal Communication capability.[60]

76. As noted above, proposed Reliability Standards TOP-001-3, Requirements R19 and R20 and IRO-002-4, Requirement R1 address primary data exchange capabilities of the transmission operator, balancing authority and reliability coordinator, respectively. However, the proposed TOP and IRO Reliability Standards do not appear to address testing requirements of alternative or less frequently used data exchange capabilities.

Commission Proposal

77. The Commission is concerned that the proposed TOP and IRO Reliability Standards do not appear to address testing requirements for alternative or less frequently

[60] Reliability Standard COM-001-2, Requirement R9 states: "[e]ach Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours."

used mediums for data exchange to ensure they would properly function in the event that the primary or more frequently used data exchange capabilities failed. The Commission seeks comment on whether and how the TOP and IRO Reliability Standards address the testing of alternative or less frequently used data exchange capabilities for the transmission operator, balancing authority and reliability coordinator. If NERC or others believe that testing requirements for alternative or less frequently used mediums for data exchange is not necessary, we seek comment on why it is not necessary.

III. Information Collection Statement

78. The collection of information contained in this Notice of Proposed Rulemaking is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[61] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[62] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

79. We solicit comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the

[61] 44 U.S.C. 3507(d) (2012).

[62] 5 C.F.R. § 1320.11 (2014).

quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically, the Commission asks that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

Public Reporting Burden: The Commission proposes to approve revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards. These revisions will impose new or revised, or retire requirements for the balancing authority, transmission operator, generator operator, distribution provider, generator owner, load-serving entity, purchasing-selling entity, transmission service provider, interchange authority, transmission owner, reliability coordinator, planning coordinator, and transmission planner functions. The Commission based its paperwork burden estimates on the NERC compliance registry as of May 15, 2015. According to the registry, there are 11 reliability coordinators, 99 balancing authorities, 450 distribution providers, 839 generator operators, 80 purchasing-selling entities, 446 load-serving entities, 886 generator owners, 320 transmission owners, 24 interchange authorities, 75 transmission service providers, 68 planning coordinators, 175 transmission planners and 171 transmission operators. The estimates are based on the change in burden from the current standards to the proposed. Not all entity types would experience an increase in burden, which is reflected by absence of those entities from the chart below.

Collectively, the proposed TOP and IRO Reliability Standards along with revised definitions provide for certain enhancements over the currently-effective TOP and IRO Reliability Standards.[63] For example, the revised definitions of operational planning analysis and real-time assessment, which are applicable to multiple proposed TOP and IRO Reliability Standards, were enhanced and provide significant additional detail over the currently-effective definitions such as including inputs that were identified as contributing to past outages on the bulk electric system.[64] As another example, the new proposed Reliability Standard IRO-017-1 establishes operational planning requirements for each reliability coordinator to implement an outage coordination process for its area that address a reliability gap identified in the Southwest Outage Blackout Report and in the Remand NOPR.[65] The Commission estimates the annual reporting burden and cost as follows:

[63] NERC Petition at 10.

[64] NERC Petition at 14.

[65] NERC Petition at 17.

RM15-16-000 (Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards)						
	Number of Respondents[66] (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[67] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
FERC-725A						
TOP-001-3	196 (TOP & BA)	1	196	96 hrs. $6,369	18,816 hrs., $1,248,441	96 hrs, $6,369
TOP-002-4	196 (TOP & BA)	1	196	284 hrs. $18,843	55,664 hrs., $3,693,306	284 hrs., $18,843
TOP-003-3	196 (TOP & BA)	1	196	230 hrs. $15,260	45,080 hrs., $2,991,058	230 hrs., $15,260
Sub-Total for FERC-725A					123,252 hrs., $7,932,806	
FERC-725Z						
IRO-001-4[68]	177 (RC & TOP)	1	177	0 hrs. $0	0 hrs. $0	0 hrs. $0
IRO-002-4	11 (RC)	1	11	24 hrs. $1,592	264 hrs., $17,516	24 hrs., $1,592
IRO-008-2	11 (RC)	1	11	228 hrs. $15,127	2,508 hrs., $166,405	228 hrs., $15,127
IRO-010-2	11 (RC)	1	11	36 hrs. $2,388	396 hrs., $26,274	36 hrs., $2,388
IRO-014-3	11 (RC)	1	11	12 hrs. $796	132 hrs., $8,758	12 hrs., $796
IRO-017-1	180 (RC, PC, & TP)	1	180	218 hrs. $14,464	39,240 hrs., $2,603,574	218 hrs., $14,464
Sub-Total for FERC-725Z					42,540 hrs., $2,822,529.00	

[66] The number of respondents is the number of entities for which a change in burden from the current standards to the proposed exists, not the total number of entities from the current or proposed standards that are applicable.

[67] The estimated hourly costs (salary plus benefits) are based on Bureau of Labor Statistics (BLS) information, as of April 1, 2015, for an electrical engineer ($66.35/hour). These figures are available at http://bls.gov/oes/current/naics3_221000.htm#17-0000.

[68] IRO-001-4 is a revised standard with no increase in burden.

Retirement of current standards currently in FERC-725A	457(RC, TOP, BA, TSP, LSE, PSE, & IA)	1	457	-223 hrs. -$14,796	-101,911 hrs., -$6,761,794	-223 hrs. -$14,796
NET TOTAL of NOPR in RM15-16					**63,881 hrs, $3,993,540**	

Title: FERC-725Z, Mandatory Reliability Standards: IRO Reliability Standards, and FERC-725A, Mandatory Reliability Standards for the Bulk-Power System

Action: Proposed Changes to Collections.

OMB Control Nos: 1902-0276 (FERC-725Z); 1902-0244(FERC-725A)

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: On-going.

80. Necessity of the Information and Internal review: The Commission has reviewed the requirements pertaining to the proposed Reliability Standards TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 and made a determination that the proposed requirements of these standards are necessary to implement section 215 of the FPA. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

81. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

82. Comments concerning the information collections proposed in this NOPR and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference OMB Control Nos. 1902-0276 (FERC-725Z) and 1902-0244 (FERC-725A)) in your submission.

IV. Environmental Analysis

83. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[69] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[70] The actions approved herein fall within this categorical exclusion in the Commission's regulations.

[69] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

[70] 18 CFR 380.4(a)(2)(ii).

V. Regulatory Flexibility Act Analysis

84. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities. [71] The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[72] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from a standard based on megawatt hours).[73] Proposed Reliability Standards TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 are expected to impose an additional burden on 196 entities (reliability coordinators, transmission operators, balancing authorities, transmission service providers, and planning authorities). Comparison of the applicable entities with the Commission's small business data indicates that approximately 82 of these entities are small entities that will be affected by the proposed Reliability Standards.[74] As discussed above, proposed Reliability Standards

[71] 5 U.S.C. 601-12.

[72] 13 C.F.R. § 121.101 (2013).

[73] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77343 (Dec. 23, 2013).

[74] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 750 employee threshold for each affected entity to conduct a comprehensive analysis.

TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 will serve to enhance reliability by imposing mandatory requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. The Commission estimates that each of the small entities to whom the proposed Reliability Standards TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 applies will incur costs of approximately $147,364 (annual ongoing) per entity. The Commission does not consider the estimated costs to have a significant economic impact on a substantial number of small entities. The Commission seeks comment on this proposal.

VI. Comment Procedures

85. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 Days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM15-16-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

86. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not

in a scanned format. Commenters filing electronically do not need to make a paper filing.

87. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

88. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

89. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

90. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

91. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 CFR Part 40

By direction of the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

May 2015
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its May 14, 2015 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

E-1 – Press Release

FERC conditionally accepts compliance filings

E-2, *ISO New England Inc.*, Docket No. ER13-1957-000, *et al*. This order addresses the filings submitted to comply with the interregional transmission coordination and cost allocation requirements of Order No. 1000 by neighboring transmission planning regions ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, LLC. The order finds the compliance filings partially comply with the interregional transmission requirements adopted in Order No. 1000, and conditionally accepts them, subject to further compliance filings.

FERC conditionally accepts compliance filings

E-3, *Public Service Company of Colorado*, Docket No. ER13-75-006, *et al.* This order addresses the Filing Parties' third Order No. 1000 regional compliance filing and requests for rehearing of the Commission's second compliance order. The order denies the rehearing requests and rejects in part and accepts in part the Filing Parties' proposed tariff revisions, subject to conditions.

FERC conditionally accepts compliance filings

E-4, *Avista Corporation*, Docket No. ER13-94-004, *et al*. This order conditionally accepts for filing, subject to further compliance filing, ColumbiaGrid Public Utilities' third Order No. 1000 compliance filings, effective January 1, 2015.

H-4	P-1892-027 P-1855-046 P-1904-074	TransCanada Hydro Northeast Inc.

CERTIFICATES

C-1	CP14-513-000	Impulsora Pipeline, LLC
C-2	CP14-509-000	Paiute Pipeline Company
C-3	CP14-522-000	Algonquin Gas Transmission, LLC
C-4	OMITTED	
C-5	CP15-161-000	Roadrunner Gas Transmission, LLC
C-6	CP15-32-000 CP15-33-000	Black Hills Shoshone Pipeline, LLC Energy West Development, Inc.

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

FERC denies rehearing

E-5, *ENE* (*Environment Northeast) v. Bangor Hydro-Electric Co.*, Docket No. EL13-33-001, *et al.* This order denies requests for rehearing of two Commission orders establishing hearing procedures for two complaints challenging the New England Transmission Owners' return on equity.

FERC denies rehearing

E-6, *Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Co.*, Docket Nos. EL12-59-001 & EL13-78-001 (consolidated). The order denies requests for rehearing of two Commission orders establishing hearing procedures for two complaints in which Golden Spread challenged the return on equity in Southwestern Public Service Co.'s (SPS) transmission formula rates found in the Replacement Power Sales Agreement between SPS and Golden Spread, and the transmission revenue requirement in Xcel Energy Inc.'s open access transmission tariff.

FERC conditionally accepts tariff revisions

E-7, *Nevada Power Company*, Docket Nos. ER15-1196-000 and -001. This order conditionally accepts, subject to further filings, proposed revisions to NV Energy's Open Access Transmission Tariff to enable its participation in the California Independent System Operator Corporation's Energy Imbalance Market.

FERC denies request

E-8, *Northern States Power Company, a Minnesota corporation*, Docket No. QM15-2-000. This order denies Northern States Power Company's (NSPM) application to terminate its obligation to purchase electric energy and capacity from a qualifying facility owned by Twin Cities Hydro LLC (Twin Cities), in light of NSPM's failure to demonstrate that Twin Cities has nondiscriminatory access to the capacity market of the Midcontinent Independent System Operator, Inc.

FERC authorizes a transfer of an electric generating facility

E-9, *PowerMinn 9090, LLC*, Docket No. EC15-76-000. This order authorizes the transfer of a 64-megawatt electric generating facility from PowerMinn 9090 and Fibrominn, LLC to Benson Power, LLC.

FERC authorizes issuance of securities

E-10, *NorthWestern Corporation*, Docket No. ES15-14-000. This order grants NorthWestern's request for authorization to issue securities under section 204 of the Federal Power Act. Though NorthWestern's *pro forma* interest coverage ratio is below 2.0, the facts set forth by NorthWestern, including that its retail rates allow for recovery of its interest expense for the proposed issuances of securities, provide the Commission an alternative basis upon which to conclude that the proposed issuances of securities should not impair NorthWestern's ability to both service the proposed securities and to continue to provide service as a public utility.

FERC accepts a filing

E-12, *Entergy Services, Inc.*, Docket No. ER07-956-008. The order accepts Entergy's comprehensive bandwidth recalculation report for calendar year 2006. The order also accepts Entergy's application of the bandwidth formula to Entergy Texas and Entergy Gulf States Louisiana, the successors to Entergy Gulf States, an entity which no longer exists.

FERC finds compliance filing moot

E-13, *Entergy Services, Inc.*, Docket Nos. ER10-3357-000 and 001. This order finds that Entergy's compliance filing in response to Order Nos. 729 and 676-E is moot due to Entergy's December 19, 2013 integration into Midcontinent Independent System Operator, Inc., which resulted in the cancellation of Entergy's Open Access Transmission Tariff.

FERC grants a petition for declaratory order

E-14, *Avista Corporation*, Docket No. EL15-19-000. The order grants a petition for a declaratory order finding that Avista is exempt from certain books and records-related requirements under the Public Utility Holding Company Act of 2005.

FERC grants request for limited waiver

E-15, *Southwest Power Pool, Inc.*, Docket No. ER15-990-000. This order grants SPP's request for limited waiver of certain provisions in Attachment AE of SPP's tariff to recognize the establishment of certain resource hubs in SPP's Integrated Marketplace.

FERC denies rehearing

G-1, *CAlifornians for Renewable Energy, Inc., Michael E. Boyd, Robert M. Sarvey v. Pacific Gas and Electric Company*, Docket No. RP13-436-001. This order denies a request for rehearing filed by CAlifornians for Renewable Energy, Inc., Michael E. Boyd, and Robert M. Sarvey of the Commission's order denying their complaint that Pacific Gas and Electric Company had violated the terms and conditions of its blanket certificate through failure to meet requirements to maintain its natural gas pipeline system, with regard to events leading up to, during, and following the San Bruno pipeline explosion.

FERC grants intervention and rehearing

H-2, *Brookfield Smoky Mountain Hydropower, LLC*, Project No. 2169-109. This order grants American Whitewater's motion to intervene and request for rehearing of Commission staff's March 11, 2015 order, which incorporated into the license a revised Clean Water Act section 401(a) Water Quality Certification and amended the operating plan for the Brookfield Smokey Mountain Hydro Project No. 2169, located on the Little Tennessee River in Graham and Swain counties, North Carolina, and Blount and Monroe counties, Tennessee. The order amends the operating plan to include American Whitewater as a consulted entity for high flow event planning.

FERC proposes a rule

H-3, *Commencement of Assessment of Annual Charges*, Docket No. RM-15-18-000. This Notice of Proposed Rulemaking (NOPR) proposes to amend the Commission's regulations to commence assessing annual charges to hydropower licensees and exemptees, other than state or municipal entities, with respect to licenses and exemptions authorizing unconstructed projects and new capacity, beginning two years from the effective date of the project license, exemption, or amendment authorizing new capacity, rather than on the date that project construction starts. The proposed revisions will provide administrative efficiency and promote certainty among licensees, exemptees, and Commission staff as to when annual charges will commence.

FERC grants rehearing and approves a filing

H-4, *TransCanada Hydro Northeast, Inc*, Project Nos. 1892-027, 1855-046, and 1904-074. This order grants TransCanada's request for rehearing of a February 21, 2014 determination letter filed by the Director, Office of Energy Projects, on a study plan submitted by TransCanada, licensee for the Wilder Hydroelectric Project No. 1892, Bellows Falls Hydroelectric Project No. 1855, and the Vernon Hydroelectric Project No. 1904, located on the Connecticut River in New Hampshire and Vermont. The order deletes the requirement for a hydroacoustic study to monitor downstream passage of

juvenile American shad and adult American eels at one of the projects and approves TransCanada's Revised Study 22 regarding juvenile shad.

FERC authorizes a cross-border natural gas pipeline project

C-1, *Impulsora Pipeline,LLC,* Docket No. CP14-513-000. This order issues a Presidential Permit and grants authorization under section 3 of the Natural Gas Act to Impulsora Pipeline for a new border crossing pipeline facility that will transport Texas-sourced gas gathered from a proposed intrastate pipeline to a power plant to be constructed near Colombia, Nuevo Léon, Mexico. The project will consist of one 36-inch-diameter, 4,000-foot-long pipeline and one 12-inch-diameter, 2,500-foot-long pipeline that will run parallel to the 36-inch-diameter pipeline. The export facilities will have a design capacity to transport approximately 1.12 million cubic feet of gas per day. In addition to the two pipelines, Impulsora proposes to construct and operate a meter and pigging equipment, consisting of one 12-inch pig receiver and one 36-inch pig receiver that will be situated on 0.6 acre of land.

FERC authorizes new natural gas pipeline facilities

C-2, *Paiute Pipeline Company*, Docket No. CP14-509-000. This order issues a certificate of public convenience and necessity to Paiute Pipeline Company to construct and operate the proposed Elko Area Expansion Project in Nevada. The project would include the construction and operation of approximately 35.2 miles of 8-inch diameter pipeline, modification of Paiute's Elko City Gate and the construction and operation of a new interconnection with Ruby Pipeline, LLC. The proposed project will enable Paiute to provide 21,994 dekatherms of gas per day of incremental firm transportation service to Southwest Gas Corporation-Northern Nevada and Newmont Mining Corporation. The order also examines and rejects an alternative route sponsored by the Bureau of Land Management and Prospector Pipeline Company.

FERC authorizes new natural gas pipeline facilities

C-3, *Algonquin Gas Transmission, LLC,* Docket No. CP14-522-000. This order grants Algonquin Gas Transmission a certificate of public convenience and necessity to construct and operate the Salem Lateral Project which will consist of approximately 1.2 miles of 16-inch-diameter lateral pipeline and a metering and regulating station in Salem, Massachusetts. The project will connect Algonquin's HubLine to a proposed 630-megawatt, quick-start, natural gas-fired generation facility.

FERC approves letters to secretaries of the Defense and State departments

C-5, *Roadrunner Gas Transmission, LLC,* Docket No. CP15-161-000. These letters request comments from the Secretary of State and the Secretary of Defense regarding the application filed by Roadrunner Gas Transmission, LLC for authorization under section 3

of the Natural Gas Act and a Presidential Permit to site, construct, connect, operate, and maintain natural gas pipeline facilities at the international boundary between the United States and Mexico in the vicinity of San Elizario in El Paso County, Texas for the export of natural gas.

FERC grants a certificate of public convenience and necessity

C-6, *Black Hills Shoshone Pipeline, LLC*. Docket No. CP15-32-000. This order grants the requested authorizations, subject to conditions, submitted in a joint application under section 7 of the Natural Gas Act (NGA) by Black Hills Shoshone Pipeline, LLC (Black Hills) and Energy West Development, Inc. (Energy West). The order grants (1) NGA section 7(b) authorization for Energy West to abandon by sale the Shoshone Pipeline, an approximately 30-mile-long, six-inch-diameter pipeline system located in Montana and Wyoming; (2) a certificate of public convenience and necessity under NGA section 7(c) and Part 157 of the Commission's regulations authorizing Black Hills to acquire and operate the Shoshone Pipeline and to provide service at the same rates, terms, and conditions currently applicable to service under Energy West's tariff; (3) a blanket certificate in accordance with Subpart F of Part 157 of the Commission's regulations for Black Hills to perform certain routine construction, operation and abandonment activities; and (4) a blanket certificate in accordance with Subpart G of Part 284 of the Commission's regulations authorizing Black Hills to provide open access firm and interruptible transportation services.

NERC
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Lesson Learned

Real-Time Contingency Analysis Failure due to a Modeling Error

Primary Interest Groups
Reliability Coordinators (RCs)
Balancing Authorities (BAs)
Transmission Operators (TOPs)
Transmission Owners (TOs)

Problem Statement
A Real-Time Contingency Analysis (RTCA) process failed to converge for 46 minutes.

Details
During the 46-minute period of the event, the state estimator converged intermittently; however, both power flow and contingency analysis were available in study application, and operators had full visibility and control of the system via SCADA.

The system operator did not recognize that the RTCA result had been non-convergent for 29 minutes because the alert status was not in an obvious location on the screen, it was not a prominent color, and it lacked an indication that it was critical. The operator noticed that the RTCA base case diverged after a second alert, so the operator immediately attempted to manually run RTCA two additional times. This action was a procedure used to attempt to correct the problem, but neither run was successful. EMS support personnel were then contacted for assistance. Model updates were made that allowed RTCA to converge approximately 46 minutes after the initial RTCA non-convergence.

An investigation determined that there was an error in a recent model topology .csv change file. Although the topology change was done in accordance with existing processes, it was determined that the error was not present in the development environment used for testing the topology modifications and that the error was introduced during the migration of these changes to the production environment. A .csv file had been prepared with the topology changes and populated on the Development System Network Applications Database. While testing the modifications, corrections were made directly to the Development System Network Applications Database and concurrently to the file that had been used to populate the topology changes on the development system. The concurrent correction made to the file is where the human error occurred and went unnoticed. The incorrectly modified .csv file was then used to populate the topology changes on the Production System Network Applications Database.

It was also determined that the network applications display didn't show the RTCA convergence status in an obvious location, nor did the RTCA status alert clearly indicate that it was critical. In addition, the system operator didn't fully recognize and understand the critical nature of a non-convergent state estimator solution.

Corrective Actions

- A temporary fix was initiated to get a convergent solution. Once the solution was stable, EMS support personnel investigated the non-convergence and identified an error in a recent topology change made to the model, and the error was corrected immediately.
- EMS support personnel modified the process for making Network Applications Database modifications of this nature. The change process now includes an additional step whereby if any changes are made directly to the Development System Network Applications Database during testing, the file will be re-created from the Development System Network Applications Database, the changes will be compared and verified to the original file, and the newly created file will be used to populate the Production System Network Applications database.
- The network applications display was adjusted with the status information moved to a more visible area. The color of the status alert for “non-converged” was changed from brown to red. A unique audible alarm was also added to the “non-converged” status alert.
- The event was communicated to all system operators, detailing the importance of fully understanding what the different solution status terms mean.

Lessons Learned

- An additional change-control procedure needs to be in place to avoid the transfer of bad data to production after it has been successfully tested on the development system.
- For verification of changes, automated review, peer review, or both must be implemented as part of any change process.
- Real-time tools, state estimators, and contingency analysis solutions need to be validated on the production system after a model change.
- Visual tools must prominently display critical alerts to the system operator.
- System operators must be able to recognize when their tools are abnormal and react according to their severity.
- Placement of status indicators, the color of the text based upon the level of the alert, and the type of audible alert must be considered for ease of identification by the system operator.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20150601
Date Published:	June 9, 2015
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Generator Distributed Control System Impact on Automatic Voltage Regulators

Primary Interest Groups
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Generator Operators (GOPs)
Generator Owners (GOs)

Problem Statement
The RC and TOP within an RC footprint observed unusual generator reactive output following the switching of a shunt reactor near all of the generators' points of interconnection.

Details
The generators at the plant were operating with their automatic voltage regulators (AVRs) regulating to maintain a constant voltage schedule. The expected change in the generators' reactive output was initially observed when the shunt reactor was switched out of service. Shortly thereafter, the generators' reactive output immediately reduced by approximately the output of the reactor. The resulting transmission voltage was slightly higher than it was prior to the switching of the reactor.

This response initially supported the assumption that the generators' AVRs were functioning properly and automatically regulating to maintain a constant voltage schedule. However, the generators' reactive output began to slowly increase after a few seconds. Over a seven-minute period, the reactive output gradually returned to the same precontingency level it had been prior to the shunt reactor switching. Over this period of time, the transmission system voltage increased proportionally with the reactive output of the generators. The response over this period of time suggested that the generators were not automatically regulating to maintain a constant voltage schedule as had been assumed. This generator response is shown in Figure 1.

A coordinated control review with the GOP was conducted to determine why the plant's reactive output behaved in this manner. It was determined that the AVRs on all of the generators at the plant were operating to maintain a constant voltage schedule. However, the distributed control system (DCS) at the plant introduced a slower control function that would increase or decrease the AVR voltage set point until the plant's DCS reactive output objective was met. The plant's DCS reactive output objective was a megavar value entered into the DCS by the plant operator. The megavar value entered into the DCS was the value needed to meet the transmission system voltage schedule for the existing steady-state conditions. This put the DCS objective in conflict with the required postcontingency AVR response.

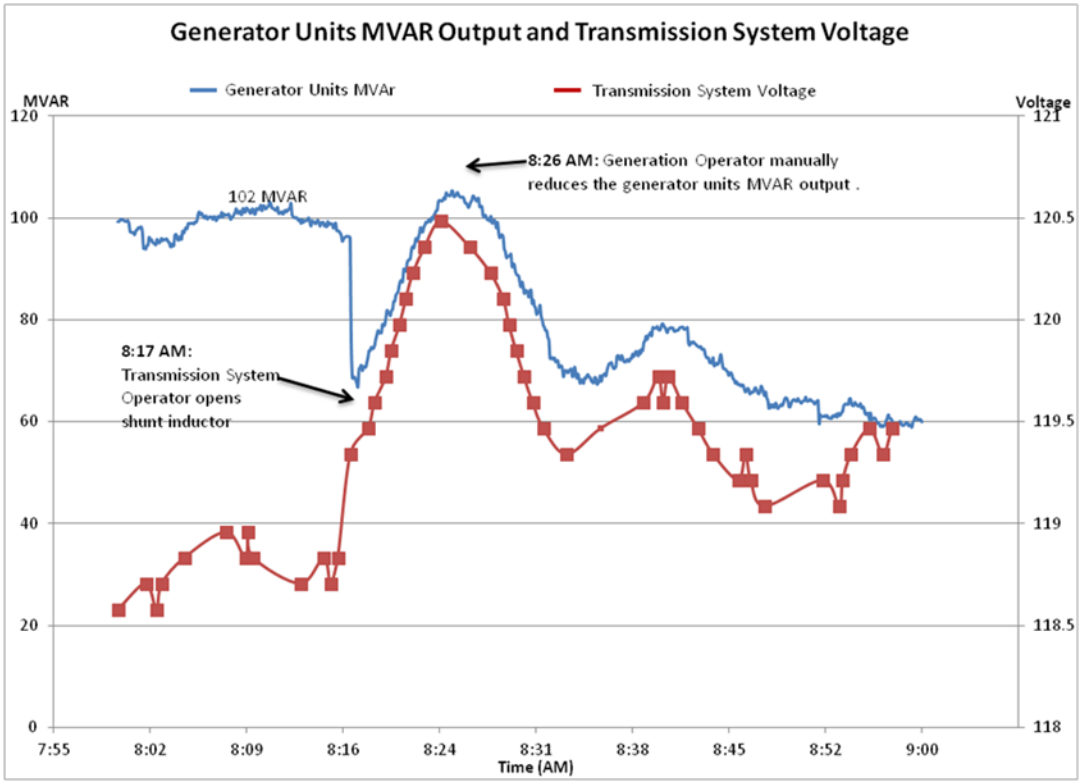

Figure 1: Generator Units MVAR Output and Transmission System Voltage

Corrective Actions

The coordinated control review with the GOP resulted in a modification of the plant's DCS to prevent this behavior. The DCS was modified to have the ability to set the reactive objective to be the transmission system voltage schedule that the plant was directed to control instead of a fixed megavar output. This control change to the DCS system resulted in the desired behavior from the plant following a contingency or a transmission element switching.

After a review of other facilities within the RC's footprint, there were multiple plants found with the same DCS issue. These have been corrected with the same or similar modifications in coordination with the GOP.

Lesson Learned

While a generator AVR may be properly set to control the voltage schedule, other plant control systems may override or counteract the appropriate AVR response. Periodic review of a plant's AVR response to system events must be conducted to determine if this occurs. If a proper AVR response is inhibited, the RC, TOP, and GOP should review the interaction of all related plant control systems to develop a corrective action plan for coordinating the plant control systems to ensure the AVR will have the uninhibited ability to control the desired voltage set point.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20150602
Date Published:	June 9, 2015
Category:	Generation Facilities

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Industry Advisory

FAC-003-3 Minimum Vegetation Clearance Distances (MVCD)

Initial Distribution: May 14, 2015

The purpose of this Advisory is to provide Transmission Owners and Generator Owners information about preliminary testing results and anticipated adjustments to the Minimum Vegetation Clearance Distances (MVCDs) specified in the NERC Reliability Standard FAC-003-3. As a result of the preliminary testing, the MVCD listed in the Standard required to prevent a flashover and improve the reliability of the Bulk Power System (BPS) will need to be increased. Transmission and Generator Owners should consider this information in their maintenance strategies or any related vegetation management programs, processes, and procedures.

NERC conducted testing as directed in the Federal Energy Regulatory Commission's (FERC's) Order No. 777 (Revisions to Reliability Standard for Transmission Vegetation Management, 142 FERC ¶ 61,208 (2013)). The testing is intended to support the MVCD calculated based on application of the Gallet equation, with the gap factors for all alternating current system voltages covered in Table 2 of the Standard. The preliminary test results, identified in a collaborative research project under contract with the Electric Power Research Institute (EPRI), determined that the current gap factor requires adjustment.

NERC will initiate efforts to correct the MVCD values in FAC-003-3 following the conclusion of validation testing expected in early to mid-summer. The final adjustments will be based solely on the validated findings of the research.

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Distribution:	**Initial Distribution:** Generator Owner, Transmission Owner **Who else will get this alert? >>** **What are my responsibilities? >>**
Primary Interest Groups:	Generation Engineering, Generation Operations, Physical Security, System Operations – Transmission Engineering, System Operators, System Operators – System Protection, Transmission Planning

Advisory:

The preliminary findings of NERC's testing determined that the current gap factor in the Gallet equation of 1.3 will likely be adjusted to a value around 1.0. This will result in increased MVCD values for all alternating current system voltages identified in Table 2 of the Reliability Standard. The adjusted MVCD values, reflecting the anticipated 1.0 gap factor, would be as follows:

Nominal AC System Voltage (kV)	MVCD at 1.0 Gap Factor (feet)														
	Sea Level up to 500 ft	Over 500 ft up to 1,000 ft	Over 1,000 ft up to 2,000 ft	Over 2,000 ft up to 3,000 ft	Over 3,000 ft up to 4,000 ft	Over 4,000 ft up to 5,000 ft	Over 5,000 ft up to 6,000 ft	Over 6,000 ft up to 7,000 ft	Over 7,000 ft up to 8,000 ft	Over 8,000 ft up to 9,000 ft	Over 9,000 ft up to 10,000 ft	Over 10,000 ft up to 11,000 ft	Over 11,000 ft up to 12,000 ft	Over 12,000 ft up to 13,000 ft	Over 13,000 ft up to 14,000 ft
765	11.6	11.7	11.9	12.1	12.2	12.4	12.6	12.8	13.0	13.1	13.3	13.5	13.7	13.9	14.0
500	7.0	7.1	7.2	7.4	7.5	7.6	7.8	7.9	8.1	8.2	8.3	8.5	8.6	8.8	8.9
345	4.3	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6
287	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.1	6.2	6.3	6.4	6.5	6.6	6.7
230	4.0	4.1	4.2	4.3	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3
161	2.7	2.7	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.3	3.3	3.4	3.5	3.6	3.6
138	2.3	2.3	2.4	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1
115	1.9	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6
88	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1
69	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5

Table 1 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units)

Nominal AC System Voltage (kV)	MVCD at 1.0 Gap Factor (meters)														
	Sea Level up to 152 m	Over 152 m up to 305 m	Over 305 m up to 610 m	Over 610 m up to 914 m	Over 914 m up to 1,219 m	Over 1,219 m up to 1,524 m	Over 1,524 m up to 1,829 m	Over 1,829 m up to 2,134 m	Over 2,134 m up to 2,438 m	Over 2,438 m up to 2,743 m	Over 2,743 m up to 3,048 m	Over 3,048 m up to 3,353 m	Over 3,353 m up to 3,657 m	Over 3,657 m up to 3,962 m	Over 3,962 m up to 4,267 m
765	3.5	3.6	3.6	3.7	3.7	3.8	3.8	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.3
500	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7
345	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.7
287	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.0	2.1
230	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6
161	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1
138	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9
115	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
88	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
69	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5

Table 2 – Table of MVCD values at a 1.0 gap factor (in metric units)

For example, the original MVCD listed in Table 2 of FAC-003-3 for 500kV at sea level was 5.15 feet. The new MVCD, listed in Table 1 above, with the adjusted gap factor is 7.0 feet.

Under FAC-003-3, Transmission Owners and Generator Owners are responsible for ensuring that vegetation encroachments do not occur within the MVCDs of applicable transmission lines. NERC is providing the preliminary findings of the research project to enable Transmission Owners and Generator Owners to make adjustments that may be appropriate in the maintenance strategies, procedures, processes, or specifications used in vegetation management programs.

Background: In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flashover distances between conductors and vegetation. FERC directed NERC to submit: (1) a schedule for testing; (2) the scope of work; (3) funding solutions; and (4) a deadline for submitting a final report on the test results to FERC, along with interim reports if a multi-year study is conducted. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. NERC submitted a compliance filing in accordance with Order No. 777 on July 12, 2013 (Compliance Filing of the N. Am. Reliability Corp., Docket No. RM12-4-000) which FERC accepted on September 4, 2013 (N. Am. Elec. Reliability Corp., Docket No. RM12-4-001).

In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing

the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team comprises NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. In March 2014, the project's scope of work and a detailed test plan was finalized with EPRI staff, members of industry, and FERC staff.

The testing project commenced in April 2014 and continued through October 2014. EPRI completed the prescribed tests aimed at determining the gap factor applied in the Gallet equation. On July 31, 2014, NERC filed an informational filing with FERC (Informational Filing of NERC, Docket Nos. RM12-4-000 and RM12-4-001) containing the details of the testing work that had been completed through the end of July. The initial analysis, as well as preliminary conclusions and recommendations, was reached in early 2015. Based on these preliminary results, it has become apparent that the gap factor used in the Gallet equation requires adjustment from 1.3 to 1.0. For additional details on the testing project, please follow this link to Project 2010-07.1 Vegetation Management.

NERC will undertake additional tests as needed to finalize the preliminary gap factor determinations, file a final report with FERC by late summer of 2015, and initiate a narrowly prescribed Standard Authorization Request for a NERC Reliability Standards development effort to adjust the MVCD values in FAC-003-3.

Contact:

Bulk Power System Awareness Group
North American Electric Reliability Corporation
3353 Peachtree Road NE
Suite 600 – North Tower
Atlanta, GA 30326

Alert ID: A-2015-05-14-01

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2015 ERO Compliance Monitoring and Enforcement Implementation Plan

Revised May 5, 2015

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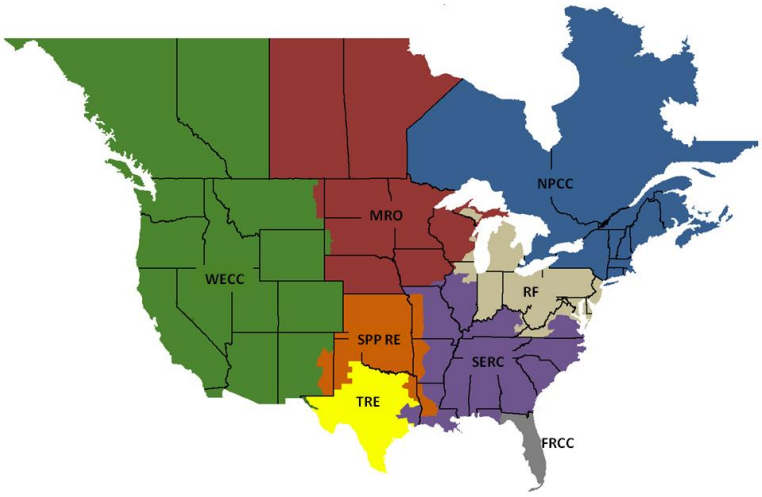
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below. The ERO Enterprise is comprised of NERC and the eight REs.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Purpose

The ERO Compliance Monitoring and Enforcement Program Implementation Plan (Implementation Plan) is the annual operating plan carried out by Compliance Enforcement Authorities (CEAs) while performing their responsibilities and duties as called for in the Compliance Monitoring and Enforcement Program (CMEP). CEAs, which consist of NERC and the eight REs, carry out CMEP activities in accordance with the NERC Rules of Procedure (ROP), including Appendix 4C, the respective Regional Delegation Agreements between NERC and each RE, and other agreements with the Canadian regulatory authorities.

Historically, the Implementation Plan has specified the NERC Reliability Standards and Requirements to be actively monitored and audited by the REs during the implementation year.[1] For the 2015 Implementation Plan and beyond, NERC will replace the approach used to develop the ERO CMEP Implementation Plan and the Actively Monitored List (AML) with processes that identify and prioritize continent-wide risks to the reliability of the BPS, as well as related Reliability Standards and registration functional categories. The new approach will provide input to a more individualized compliance oversight plan for registered entities. The transformation to focus on identifying and prioritizing risks replaces a static, one-size-fits-all list of Reliability Standards and prioritizes functions and Reliability Standards based on risk to determine the appropriate oversight method.

The NERC ROP requires that NERC provide the Implementation Plan to the REs on or about September 1 of the preceding year.[2] REs must submit their Implementation Plans to NERC for review and approval on or about October 1. Regional Implementation Plans provide:

- Details on Regional Risk Assessment processes and results,
- Reliability Standards and Requirements associated with Regional Risk Assessment results,
- Regional compliance oversight plan, which includes its annual audit plan, and
- Other key activities and processes used for CMEP implementation.

Implementation Plan

The ERO Enterprise maintains a consolidated Implementation Plan that provides guidance and implementation information common among the NERC and the eight REs.

During the implementation year, NERC or a RE may update the Implementation Plan. Updates could include, but are not limited to: changes to compliance monitoring processes, changes to regional processes, or updates resulting from a major event, FERC Order, or other matter. When updates occur, NERC will post a revised plan on the NERC website and issue a compliance communication. REs should submit updates to the NERC Compliance Operations group, which will review and act on any proposed changes. NERC will be responsible for updating the ERO CMEP Implementation Plan to reflect any RE changes and will post the updated plan to the website and issue compliance communications.

RE Implementation Plans

The Regional Implementation Plans supplement the ERO CMEP Implementation Plan and provide information that is RE-specific. The Regional Implementation Plan describes Regional risk assessments that identify risks that Regions will consider as part of their compliance oversight plan, which includes the 2015 annual audit plan.

[1] NERC ROP, Section 401 (Scope of the NERC Compliance Monitoring and Enforcement Program).

[2] NERC ROP, Section 403 (Required Attributes of RE Compliance Monitoring and Enforcement Programs).

Appendices 1.1-1.8 contain the Regional Implementation Plans. NERC will update the Implementation Plan on or about November 1 to include the Regional Implementation Plans. Regional Implementation Plans are due to NERC for review on or about October 1.

Risk-based Approach to Compliance Monitoring and Enforcement

Risk-based Compliance Monitoring

Deployment of Risk-based Compliance Oversight

Through a Reliability Assurance Initiative (RAI), NERC has transformed its compliance and enforcement program into one that is forward-looking, focuses on areas that represent a high risk to BPS reliability, and reduces the administrative burden on registered entities. The transformed approach to compliance monitoring emphasizes an examination of reliability risks as the basis for the determination of the appropriate oversight framework, including scope, frequency, and what monitoring tools are appropriate in each case.

During 2015, CEAs will begin deploying processes and tools used to support risk-based compliance oversight. NERC and the REs are committed to ensuring full transformation to risk-based compliance oversight, and NERC and the REs plan continued communications, training, and outreach throughout 2015 to support risk-based compliance oversight.

Risk-based Compliance Oversight Framework

The ERO Enterprise's Risk-based Compliance Oversight Framework (Framework) consists of processes that involve reviewing system-wide risk elements, an assessment of a registered entity's inherent risk, and, on a voluntary basis, an evaluation of a registered entity's internal controls prior to establishing a monitoring plan that is tailored to a particular entity or group of entities.

Figure 1 below illustrates the ERO Enterprise's transformation from a static compliance approach to a dynamic approach. Reliability risk is not the same for all registered entities; therefore, this Framework examines BPS risk as well as individual registered entity risk to determine the most appropriate CMEP tool to use when monitoring a registered entity's compliance with Reliability Standards. This Framework also promotes examination of how registered entities operate. As illustrated by the blue arrows in Figure 1, the Framework tailors compliance monitoring focus to those areas that pose the greatest risk to BPS reliability. The elements in Figure 1 are dynamic and are not independent; rather, they are complementary and interdependent on each another.

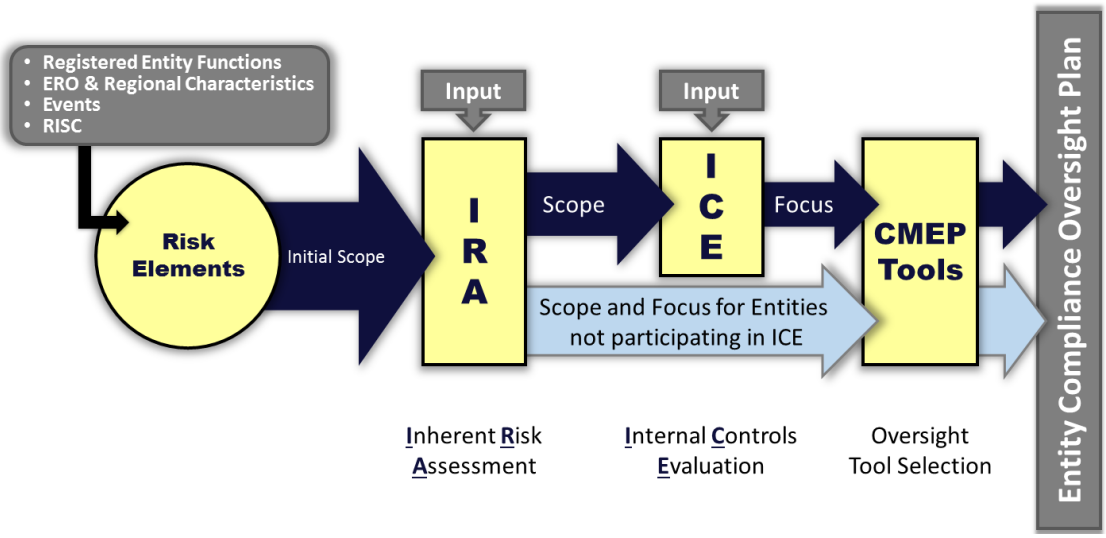


Figure 1: Risk-based Compliance Oversight Framework

Risk Elements

The first step of the Framework consists of identifying and prioritizing continent-wide risks. These risks are identified and prioritized based on, among other things, the work done by NERC staff, the Reliability Issues Steering Committee (RISC), initiatives such as the Standards Independent Experts Review Project, and risks identified in the ERO Enterprise Strategic Plan. Risks are identified and prioritized based on significance, likelihood, vulnerability, and potential impact to the reliability of the BPS. They may be categorized as operational and planning risks, as well as threats to cyber systems or physical security. While risk identification occurs on at least an annual basis, they are dynamic and continually evolve. Accordingly, periodic reviews and updates may be necessary and appropriate to address increased or emerging risks as well as reflect mitigated risks. However, the risks and associated Reliability Standards identified through this process do not constitute the entirety of risks that may affect the reliability of the BPS. Regional Entities are expected to consider local risks and specific circumstances associated with individual registered entities within their footprint when developing their compliance oversight plans.

Inherent Risk Assessment

REs perform an Inherent Risk Assessment (IRA) of registered entities to identify areas of focus and the level of effort needed to monitor compliance with NERC Reliability Standards for a particular registered entity. The IRA is a review of potential risks posed by an individual registered entity to the reliability of the BPS. An IRA considers risk factors such as assets, systems, geography, interconnectivity, prior compliance history, and overall unique entity composition when determining the compliance oversight plan for a registered entity. The IRA will be performed on a periodic basis, with the frequency based on a variety of factors, including, but not limited to, changes to a registered entity and significant changes or emergence of new reliability risks. For monitoring activities performed in 2015, REs may be in various stages of conducting IRAs for registered entities within their footprint. During 2015 and beyond, REs will continue to expand the IRA process to registered entities in their footprints based on risk and compliance monitoring schedules.

Internal Controls Evaluation

To further tailor monitoring plans in accordance with risk for registered entities in their footprints, the Regional Entities also take into account any information obtained through the processes outlined in the **Internal Control Evaluation (ICE)** Guide. For those entities who volunteer to undergo an ICE, REs will select those who will participate in the ICE process based on the risk posed by particular entities and compliance monitoring schedules.

The Internal Controls Evaluation (ICE) enables a further refinement of the registered entity's compliance oversight plan. Registered entities have an opportunity to: (i) provide, on a voluntary basis, information to their respective RE about their internal controls that address the risks applicable to the entity and for identifying, assessing, and correcting noncompliance with Reliability Standards; and (ii) demonstrate the effectiveness of such controls. As a result of the ICE, there may be additional focus of the compliance assurance activities for an entity. Registered entities may elect not to participate in an ICE. In that case, the CEA will use the results of the IRA to determine the appropriate compliance oversight strategy, including focus and tools within the determined scope.

CMEP Tools

Ultimately, the RE will determine which of the compliance monitoring tools (i.e., off-site or on-site audits, spot checks, or Self-Certifications) are warranted. REs will tailor compliance monitoring activities for registered entities in their footprint based on reliability risks. Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to remain on a three-year audit cycle. The determination of the appropriate CMEP tools will be adjusted, as needed, within a given implementation year.

Self-certifications

In the 2015 ERO CMEP Implementation Plan, the ERO identifies continent-wide reliability risks to the BPS and a core set of Reliability Standards and Requirements associated with those risks for specific registered functions.

In developing a compliance oversight plan for registered entities in its footprint, REs should support compliance assurance with these identified Standards and Requirements. Through a risk assessment, an RE may determine that regional risks or risks associated with any particular registered entity drive more, less, or different priorities, and, therefore, the RE may modify the set of core Reliability Standards or pursue compliance assurance through any monitoring tools to address those regional and entity-specific considerations. If an annual self-certification program is not included in a Regional IP, the RE will be expected to address the identified risks through other means.

Compliance Assessments for Events and Disturbances

An important component of the ERO enterprise's risk-based approach to compliance monitoring is the voluntary participation in the Compliance Assessment (CA) Process by registered entities after an event or disturbance. Through the Events Analysis Process, the ERO enterprise promotes a culture of reliability excellence that encourages an aggressive and critical self-review and analysis of operations, planning, and critical infrastructure performance. The CA Process is a complementary review of the event focused on the evaluation of compliance with Reliability Standards. A registered entity completes a CA by reviewing the facts and circumstances of an event or disturbance, identifying relevant Reliability Standards and Requirements, evaluating compliance with these Standards and Requirements, and self-reporting any potential noncompliance. Regional Entity (RE) compliance staff also assesses significant events and disturbances to improve understanding of reliability risks that may guide further compliance monitoring activities.

Registered Entity Responsibilities

The ERO enterprise encourages registered entities to perform a voluntary, systematic CA in response to all system events and disturbances. Registered entities are also expected to share the CA with the RE for all Category 2 and above events. The ERO Events Analysis process document describes the categories for events.[3] Registered entities should use the Sample Compliance Assessment Report Template (Appendix 3 of this document) when performing a CA. In addition to the completed CA template, registered entities should provide to the RE sufficient event information, such as the Brief Report or Event Analysis Report, so the RE may thoroughly understand the event. Registered entities that follow the process above to systematically evaluate their own compliance performance, identify, self-report potential noncompliance, and address reliability issues demonstrate the effectiveness of their internal controls and their commitment to a culture of compliance. Registered entities that are able to demonstrate strong internal controls and a robust culture of compliance that mitigates risk may be afforded some recognition by way of reduced levels and frequency of compliance monitoring activities. Mitigating credit for these actions is also considered during the enforcement of a noncompliance. Such credit is available to the registered entity for comprehensive compliance assessments that clearly demonstrate a systematic review of applicable Standards and, as appropriate, self-reporting.

Regional Entity Responsibilities

REs will review system event reports and CA reports provided by registered entities and may utilize a risk-based approach to prioritize these evaluations. However, the REs will conduct a regional compliance evaluation (RCE) for all Category 2 and above events. By exception, the RE may also examine lower category events that indicate the need for closer examination. As part of its independent evaluation of the CA, the RE may request additional information from the registered entity if it is needed to better understand the event. This process, while informal, may be used to recommend a formal compliance monitoring method, such as a spot check or be used to recommend the modification the scope of an upcoming audit.

The scope of RCEs and the manner in which the REs and NERC evaluate, process, and respond to these reviews is intended to reflect the significance of the event. The registered entity can greatly assist the RE by providing a thorough and systematic self-evaluation with its CA. The RE will share the RCE and CA with NERC staff.

[3] http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/Final_ERO_EA_Process_V2.1.pdf

Risk-based Enforcement

The ERO Enterprise recognizes that not all instances of noncompliance require the same type of processing and documentation and that there is a need to streamline processes for resolving minimal and moderate risk issues. This is necessary to enable the ERO Enterprise, as well as industry, to allocate resources to address the issues posing a higher level of risk to reliability. The ERO Enterprise will continue to use more formal enforcement processes, particularly Notices of Penalty, to respond to higher risk issues. Such cases can lead to the identification and implementation of above-and-beyond activities and other non-monetary sanctions, in addition to financial penalties.

Compliance Exceptions

Based on the experience with a streamlined process and a reduced record since 2013, NERC and the REs have exercised discretion when deciding whether to initiate an enforcement action for instances of noncompliance posing a minimal risk to the reliability of the BPS. Issues resolved outside of the enforcement process are referred to as compliance exceptions. The resolution of these issues outside of the enforcement process has not eliminated oversight or visibility over the issues. Rather, these issues are provided for review by NERC and FERC. The process has allowed NERC and the Regional Entities to work with registered entities to identify and mitigate minimal risk issues promptly and more efficiently. Beginning in January 2015, all minimal risk instances of noncompliance will be eligible for resolution as a compliance exception. While compliance exceptions will effectively supersede Find, Fix, Track and Report (FFT) as the process for resolving minimal risk instances of noncompliance in the future, for the time being, the FFT process remains relevant, particularly as it relates to moderate risk issues or minimal risk issues that a region may not deem appropriate to be treated a compliance exception, based on individual facts and circumstances of a particular noncompliance.

Self-Logging Program

Beginning in October 2013, NERC and the Regional Entities began to allow select registered entities with demonstrated effective management practices to self-identify, assess, and mitigate instances of noncompliance to self-log[4] minimal risk instances of noncompliance that would otherwise be individually self-reported. Properly logged items will be presumed appropriate for resolution as compliance exceptions unless there are additional risk factors identified by the CEA. This is consistent with the notion that instances of noncompliance that are self-identified through internal controls, corrected through a strong compliance culture, and documented by the registered entity, should not be resolved through the enforcement process or incur a penalty, absent a higher risk to the BPS.

The self-logging program also encourages the development and communication of management practices by registered entities and rewards registered entities for implementing demonstrated, effective controls in place to detect and correct issues as they arise.

[4] The program is also known as the aggregation program.

Risk Elements Results

The ERO Enterprise has always assessed risks to the reliability of the BPS, as well as mitigating factors that may reduce or eliminate a given reliability risk, and the ERO Enterprise will continue to do so under the Framework referenced above. The ERO Enterprise developed a risk elements Guide to describe a process for identifying risks to the BPS and associated registration functional categories and NERC Reliability Standards to those risks.

In 2015, the ERO Enterprise identified nine risk elements with specific areas of focus. REs will consider the nine risk elements, along with regional risk considerations, to develop their Regional Implementation Plans.

The risk elements identify and prioritize existing risks to the reliability of the BPS. Each of the nine risk elements below is accompanied by a table identifying Reliability Standards and Requirements associated with each risk. The risk elements serve as an input into the overall Regional Risk Assessment to support a risk-informed compliance oversight plan. Risk elements do not serve as a baseline list of Reliability Standards and Requirements, as previously identified through the AML in prior years' CMEP Implementation Plans, nor do they identify Reliability Standards and Requirements that must be audited. Rather, they provide the starting point for the analysis of regional risks which will then be reflected in the Regional Implementation Plans.

2015 Risk Elements

The nine risk elements below are not a comprehensive list of all risks to the reliability of the BPS. Where issues are being addressed through other mechanisms, they are not included herein for compliance assurance activities.[5]

1. Infrastructure Maintenance

As the BPS continues to age, lack of infrastructure maintenance is a reliability risk that continues to grow in importance.

AC Substation Equipment Failures

As reported in the State of Reliability 2014 report, AC Substation Equipment Failures had the largest positive correlation with automatic transmission outage severity in 2013. The correlation is statistically significant: a pattern and underlying dependency exists between AC substation equipment failures and transmission outage severity. While it is unclear whether or not there is a relationship between substation equipment failures and maintenance, such a relationship may exist. The issue of AC Substation Equipment Failure is one that is still being investigated, and action plans to address this concern are being developed. Thus, the ERO CMEP IP may be updated during the year to reflect new activities based on NERC's investigation.

Aging Infrastructure

The general concern of Infrastructure Maintenance has been highlighted in other NERC documents. The 2013 Long-Term Reliability Assessment highlighted this area of concern, stating:

> Aging transmission system infrastructure has many challenges, such as the availability of spare parts, the obsolescence of older equipment, the ability to maintain equipment due to outage scheduling restrictions, and the ability to keep pace with technological advancements … Larger scale "infrastructure revitalization" may be necessary in the future; however, with older generation retiring throughout the next decade, the average age of BPS generation facilities will be relatively young. Implementation of any replacement strategy and in-depth training programs

[5] For example, vegetation management and right-of-way clearances, while key priorities, are not areas of focus for compliance assurance activities because they are being addressed through other ongoing targeted initiatives.

requires additional capital investment, engineering and design resources, and construction labor resources, all of which are in relatively short supply.

Areas of Focus

Table 1 – Infrastructure Maintenance		
Standard	**Requirements**	**Entities for Attention**
PRC-005-2	R3, R4	Generator Owners Transmission Owners Distribution Provider
PRC-008-0	R1, R2	Distribution Providers Transmission Owners
PRC-011-0	R1	Distribution Providers Transmission Owners
PRC-017-0	R1	Distribution Providers Generator Owners Transmission Owners

2. Uncoordinated Protection Systems

Protection systems that trip unnecessarily can contribute significantly to the extent of an event. When protection systems are not coordinated properly, the order of execution can result in either incorrect elements being removed from service or more elements being removed than necessary. This can also occur with Special Protection Systems, Remedial Action Schemes, and Underfrequency Load Shedding and Undervoltage Load Shedding schemes. Such coordination errors occurred in the September 8, 2011 event (see recommendation 19)[6] and the August 14, 2003 event (see recommendation 21).[7] Both the RISC's ERO Priorities: RISC Updates and Recommendations report and NERC's ERO Top Priority Reliability Risks 2014-2017 report recognize protection systems as a significant risk based on the extensive work and detailed analysis contained in the State of Reliability reports from 2012 and 2013.

Areas of Focus

Table 2 – Uncoordinated Protection Systems		
Standard	**Requirements**	**Entities for Attention**
PRC-001-1.1	R3, R5	Generator Operator Transmission Operator
	R4	Transmission Operator

3. Protection System Misoperations

Protection systems are designed to remove equipment from service to avoid damage to equipment when a fault occurs. A protection system that does not trip or is slow to trip may lead to the damage of equipment (which may result in degraded reliability for an extended period of time), while a protection system that trips when it should not can remove important elements of the power system from service at times when they are needed most. Unnecessary trips can even start cascading failures as each successive trip can cause another protection system to trip.

NERC's 2012 and 2013 State of Reliability Reports identified protection system misoperations as a significant threat to BPS reliability. Additional activities are needed to ensure this risk is managed adequately.

[6] See Arizona-Southern California Outages on September 8, 2011.

[7] See Final Report on the August 14, 2003 Blackout.

Key Finding 3 of NERC's State of Reliability 2014 report was based on the continuing history of misoperations being a significant contributor to events. The report notes:

> In 2013, there were 71 transmission-related system disturbances that resulted in a NERC Event Analysis reported event. Of those 71 events, 47 (about 66 percent) had associated misoperations. Of these 47 events, 38 (about 81 percent) experienced misoperations that were contributory to or exacerbated the severity of the event. In several cases, multiple misoperations occurred during a single disturbance. Cause coding has not yet been completed for all 2013 events, but it is estimated that there were 60–75 misoperations associated with these 38 reportable events. Therefore, out of approximately 2,000 total misoperations in 2013, approximately 3.0 to 3.5 percent were causal to or exacerbated by the severity of reportable system disturbances.

Both the RISC's ERO Priorities: RISC Updates and Recommendations report and NERC's ERO Top Priority Reliability Risks 2014-2017 report recognize protection systems and their failures as a significant risk based on the extensive work and detailed analysis contained in the State of Reliability reports from 2012 and 2013.

Areas of Focus

Table 3 – Protection System Misoperations

Standard	Requirements	Entities for Attention
PRC-004-2.1a	R1.	Transmission Owner Distribution Provider
	R2.	Generator Owner
PRC-016-0.1	R1, R2	Transmission Owner Generator Owner Distribution Provider
PRC-023-3[8]	R1.	Transmission Owner Generator Owner Distribution Provider
PRC-025-1	R1	Transmission Owner Generator Owner Distribution Provider

4. Workforce Capability

A lack of knowledge, experience, and capabilities is a common threat in any industry that relies on skilled workers. The RISC, in its ERO Priorities: RISC Updates and Recommendations report, highlighted Workforce Capability and Human Error as a priority area needing focus. Findings of the RISC focused around the need to improve organizational performance and culture to ensure support for the individual worker to gain knowledge and address known issues in advance of their reoccurrence. This is also reflected in NERC's ERO Top Priority Reliability Risks 2014-2017 report.

NERC has also identified the challenge of maintaining a robust and knowledgeable workforce for a number of years. In the 2013 Long-Term Reliability Assessment, NERC notes, "Workers entering the power industry will be tasked with understanding and implementing a variety of new technologies and smarter systems and devices. Across the industry, there is substantial interest in training and hiring workers to support these industry needs as well as transferring the expertise and knowledge of retiring workers."

[8] Reliability Standard PRC-023-3 is effective October 1, 2014. However, PRC-023-2 remains relevant as Criterion 6 of Requirement R1 will remain in effect until PRC-025-1 is fully implemented pursuant to its phased in implementation plan.

Areas of Focus

Table 4 – Workforce Capability		
Standard	**Requirements**	**Entities for Attention**
CIP-004-3a	R1, R2	Balancing Authority Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner
EOP-001-2.1b	R2, R3 R4	Transmission Operator Balancing Authority
EOP-003-2	R8.	Transmission Operator Balancing Authority
EOP-005-2	R10.	Transmission Operator
	R11.	Transmission Operator Transmission Owner Distribution Provider
	R17.	Generator Operator
EOP-006-2	R9, R10	Reliability Coordinator
PER-005-1	R3.	Reliability Coordinator Balancing Authority Transmission Operator
TOP-004-2	R6	Transmission Operator

5. Monitoring and Situational Awareness

Without the right tools and data, operators can make uninformed decisions which may or may not be appropriate to ensure reliability for the given state of the system. NERC's ERO Top Priority Reliability Risks 2014-2017 notes that "stale" data and lack of analysis capabilities contributed the 2003 and 2011 events. Certain essential functional capabilities must be in place, with up-to-date information, available for use on a regular basis, and utilized by staff to make informed decisions.

An essential component of Monitoring and Situational Awareness is the availability of information when needed. Unexpected outages of tools, or planned outages without appropriate coordination or oversight, can leave operators without visibility to some or all of the system they operate. While failure of a decision-support tool is rarely the cause of an event, such failures manifest as latent risk that further hinders the decision-making capabilities of the operator. One clear example of this is the August 14, 2003 event.

NERC has analyzed data and identified that outages of tools and monitoring systems are fairly common occurrences. The RISC's ERO Priorities: RISC Updates and Recommendations report, NERC's ERO Top Priority Reliability Risks 2014-2017 report, and the Cyber Attack Task Force final report recognize this concern.

Areas of Focus

Table 5 – Monitoring and Situational Awareness		
Standard	**Requirements**	**Entities for Attention**
EOP-010-1[9]	R2	Reliability Coordinator
IRO-002-2	R6, R7, R8	Reliability Coordinator
IRO-005-3.1a	R1	Reliability Coordinator
IRO-008-1	R1, R2	Reliability Coordinator
IRO-014-1	R1	Reliability Coordinator
PRC-001-1.1	R6	Transmission Operator Balancing Authority
TOP-002-2.1b	R4, R19	Transmission Operator Balancing Authority
	R11	Transmission Operator

[9] EOP-010-1 becomes effective on April 1, 2015. Pursuant to the implementation plan, Requirement 2 of EOP-010-1 will become effective on the first day following the retirement of IRO-005-3.1a.

Table 5 – Monitoring and Situational Awareness		
Standard	**Requirements**	**Entities for Attention**
TOP-006-2	R2	Reliability Coordinator Transmission Operator Balancing Authority
TOP-008-1	R4	Transmission Operator
FAC-011-2	R1, R2, R3	Reliability Coordinator
FAC-014-2	R5, R6	Reliability Coordinator Planning Authority Transmission Planner Transmission Operator

6. Long Term Planning and System Analysis

Long term planning and system analysis is related to several other areas (such as increased use of DSM, integration of variable generation, changes in load and system behavior, Smart Grid, increased dependence on natural gas, fossil requirements and retrofit outage coordination, nuclear generation retirements and outages, and resource planning). Long-term planning and analysis have been highlighted as a concern in RISC's ERO Priorities: RISC Updates and Recommendations report, and in NERC's ERO Top Priority Reliability Risks 2014-2017 report.

Areas of Focus

Table 6 – Long Term Planning and System Analysis		
Standard	**Requirements**	**Entities for Attention**
TPL-001-0.1[10]	R1.	Planning Authority Transmission Planner

7. Threats to Cyber Systems

Threats to cyber systems remain an area of significant importance. The need for attention in this area is addressed in the 2013 Long-Term Reliability Assessment report, in the RISC's ERO Priorities: RISC Updates and Recommendations report, the Cyber Attack Task Force final report, and in NERC's ERO Top Priority Reliability Risks 2014-2017 report. The risk includes threats and vulnerabilities that result from compromise of technology or communications that support the reliable operations of the BPS.

Areas of Focus[11]

Table 7 – Cyber Security		
Standard	**Requirements**	**Entities for Attention**
CIP-002-3	R2, R3	Balancing Authority Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner

[10] The effective date of TPL-001-4 is January 1, 2015. However, as a result of the phased implementation plan, earlier versions of the TPL Reliability Standards are referenced here.

[11] While Table 7 lists the CIP version 3 Reliability Standards (as those are currently enforceable), the ERO, through release of its Cyber Security Reliability Standards CIP V5 Transition Guidance, actively encourages and supports registered entities transitioning from compliance with the version 3 Reliability Standards directly to the version 5 Reliability Standards. As stated in that guidance, NERC and the Regional Entities will take a flexible compliance monitoring and enforcement approach for the CIP Reliability Standards, recognizing that the details of implementing a version 3 to version 5 transition may cause a significant impact on certain compliance monitoring activities.

Table 7 – Cyber Security		
Standard	**Requirements**	**Entities for Attention**
CIP-003-3	R4, R6	Balancing Authority Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner
CIP-004-3a	R3, R4	Balancing Authority Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner
CIP-005-3a	R1, R4	Balancing Authority Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner
CIP-006-3	R1, R4, R5	Balancing Authority Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner
CIP-007-3a	R1, R2, R4, R6, R8	Balancing Authority Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner
CIP-009-3	R1, R2	Balancing Authority Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner

8. Human Error

Human Error remains a key focus for the ERO Enterprise. Included in this subset are communication errors which can pose a significant potential risk to BPS reliability. Human Error was identified as a key issue by both the RISC in its ERO Priorities: RISC Updates and Recommendations report and by NERC in its ERO Top Priority Reliability Risks 2014-2017 report.

Areas of Focus

Table 8 – Human Error		
Standard	**Requirements**	**Entities for Attention**
COM-002-2	R2.	Reliability Coordinator Transmission Operator Balancing Authority

9. Extreme Physical Events

Extreme Physical Events are those events that result in extensive damage to equipment, irrespective of cause. Such events could include earthquake, GMD events, high wind, flooding, physical attack, or sabotage. NERC identified this concern as a significant risk in its ERO Top Priority Reliability Risks 2014-2017 report. As concluded in the report, risk avoidance is insufficient to manage this risk, and additional focus must be given to those things that focus on resiliency and recovery.

Risk mitigation efforts (reducing the potential consequence) are underway, but additional focus is needed to address and minimize both the magnitude and duration of the consequences of an extreme physical event.

Areas of Focus[12]

Table 9 – Extreme Physical Events		
Standard	**Requirements**	**Entities for Attention**
EOP-002-3.1	R6, R7, R8	Balancing Authority Reliability Coordinator
EOP-004-2	R2	Reliability Coordinator Balancing Authority Transmission Owner Transmission Operator Generator Owner Generator Operator
EOP-005-2	R1, R6	Transmission Operator
EOP-005-2	R9.	Transmission Operator
EOP-006-2	R1.	Reliability Coordinator
EOP-008-1	R3	Reliability Coordinator
EOP-008-1	R4	Balancing Authority Transmission Operator
EOP-010-1	R1.	Reliability Coordinator
	R3.	Transmission Operator
TPL-002-0b	R1.	Planning Authority Transmission Planner
TPL-003-0b	R1.	Planning Authority Transmission Planner
TPL-004-0a	R1.	Planning Authority Transmission Planner

Regional Risk Assessments

When considering risk elements, REs will perform a Regional Risk Assessment, identifying risks specific to the region that could potentially impact the reliability of the BPS. After determining region-specific risks, REs will also identify the related Reliability Standards and Requirements associated with those risks. These Reliability Standards and Requirements are not intended to be a static list that must be examined during all Compliance Audits. Rather, the risk elements identified by the RE will serve as input considerations when conducting an IRA for a registered entity.

REs are ultimately responsible for identifying and prioritizing risk elements within their footprints. REs should consider risk elements as an input into their Regional Risk Assessments. In doing so, REs are expected to:

- Gather and review RE-specific risk reports and operational information (e.g. interconnection points and critical paths, system geography, seasonal/ambient conditions, etc.),
- Review and prioritize potential RE-specific risks, and
- Identify associated Reliability Standards and Requirements that will be inputs into the IRAs, ICE, and ultimately the compliance oversight plan.

The Regional Implementation Plans will describe the process and results. It should explain how it identified the risk in a particular RE footprint, including reasons why any risk elements identified above are not included or applicable to the RE footprint. Although each RE will consider risk elements, and may use similar risk considerations, the output of the Regional Risk Assessments may differ as a result of regional characteristics and the uniqueness of each RE's footprint.

Regional Compliance Oversight Plan

Based on the RE's consideration and assessment of risk elements and Regional Risk Assessments, each RE will develop a compliance oversight plan, which, in 2015, will include, at a minimum, the list of planned audits for

[12] CIP-014-1 – Physical Security also addresses extreme physical events, but it is not yet FERC-approved. Table 9 may be modified to reflect the Requirements of CIP-014-1 following such approval.

Reliability Coordinators, Balancing Authorities, and Transmission Operators that are in the three-year audit cycle. REs may also identify other registered entities that it will monitor through appropriate CMEP tools based on risk elements and Regional Risk Assessments, and the application of IRA and ICE.

NERC Oversight of Regional Implementation Plans

NERC collects and reviews the Regional Implementation Plans prior to posting the final version of the ERO CMEP Implementation Plan. NERC oversight of the Regional Implementation Plans will focus on how the REs conducted Regional Risk Assessments and how the assessments' results ultimately led to the compliance oversight plan.

The RE should document all processes, conclusions, and results used to develop a registered entity's oversight plan and will not need to obtain prior approval from NERC on oversight plans. However, REs should maintain supporting documentation for review by NERC in connection with its oversight of the compliance assurance program.

The application of the Framework by the REs will reflect RE-specific circumstances including, as noted above, varying stages of conducting IRAs and ICEs. NERC oversight and regular training will ensure that all processes discussed herein are implemented in a consistent manner throughout the ERO Enterprise.

Revision History

Version	Date	Revision Detail
Version 0.0	September 8, 2014	Initial release of ERO CMEP IP
Version 1.0	November 18, 2014	ERO CMEP IP updated to include Regional Entity IPs in Appendices. Additional updates include: • Added section and guidance on Compliance Assessments for Events and Disturbances. Refer to "Risk-based Compliance Monitoring" section and Appendix B. • Added details and guidance for Self-Certification requirements for registered entities in 2015. Refer to "Risk-based Compliance Monitoring" section.
Version 1.1	May 5, 2015	Made updates to Regional Entity IPs in Appendices. Updates reflected in Bold/Underline font. Some specific changes to note include: • NPCC IP-Noted formation of its Risk Assessment group under compliance monitoring and made updates to its compliance oversight plan in Section 4. • RF IP-Added paragraph under self-certifications to capture additional self-certifications that they request throughout the year, which will require entities to provide supporting documentation along with their self-certifications submittals. • Texas RE IP- Updated Regional Risk Element "Operational Communication" by removing MOD-001-1a R4 and R5. Those Standards are not enforceable in the Interconnection. Also updated the CIP outreach to indicate that outreach is occurring with every audit and will be part of TRE's May Workshop with additional details to follow.

Appendix A1 - Florida Reliability Coordinating Council (FRCC) 2015 CMEP Implementation Plan

This Appendix contains the CMEP Implementation Plan (IP) for the FRCC as required by the NERC Rules of Procedure.

1. Compliance Monitoring and Enforcement

1.1 CMEP IP Highlights and Material Changes

- In mid-2014, the FRCC Compliance department reorganized to create a department called Risk Assessment and Mitigation (RAM). This group will be focused on risk assessment both before a monitoring activity takes place to help determine the scope of monitoring oversight, and after a possible violation is discovered to help determine the risk posed by that violation so the most efficient disposition can take place. The risk evaluation of an entity, which precedes the entity's compliance oversight plan, will include the Inherent Risk Assessment and voluntary Internal Controls Evaluation(s) of registered entities. In addition to performing risk determinations, RAM is the registered entities' primary contact for self-reporting and mitigation plans.
- The formation of the RAM group and associated new division of responsibilities, has enabled the FRCC enforcement group to concentrate on violation determination and disposition, and compliance department metrics.
- Audit notification letters will be sent to the registered entities ninety (90) days prior to commencement of a Compliance Audit.
- Per CMEP section 3.1.4.2, audit period End Dates are being modified to thirty (30) days following the date of the audit notification letter. The audit period will still begin on the day after the End Date of the registered entity's prior Compliance Audit by the FRCC (or the later of June 18, 2007 or the date the registered entity became subject to Reliability Standards if the registered entity has not previously been subject to a Compliance Audit).
- Compliance audits conducted in 2015 will include a management review of any possible non-compliance findings prior to the completion of the audit. In order to facilitate the management review, audit exit briefings may be conducted remotely, following on-site activities. However, the audit team will present a summary briefing prior to concluding the on-site portion of the audit.

1.2 Other Regional Key Initiatives & Activities

- FRCC enforcement will include the "Exception" method as an option for disposition of minimal risk non-compliances in 2015.
- The FRCC enforcement program will reserve enforcement actions to include the Find, Fix, Track and Report process and Notices of Penalties for those non-compliances that pose moderate or serious/ substantial risks to the reliability of the BPS. As to other non-compliances, FRCC enforcement will exercise appropriate discretion to initiate the Exception process for minimal risk non-compliances of Reliability Standards.
- FRCC will continue to evaluate registered entities for potential inclusion into the Entity Self-Logging program (formerly known as the "Aggregation" pilot program) which allows those registered entities that have demonstrated effective management practices to keep track of minimal risk non-compliances (and associated mitigation) on a log that is periodically reviewed by FRCC.

2. Regional Risk Assessment Process

The FRCC has reviewed the nine ERO identified risk elements and associated areas of focus for implementation plan coordination and concurs with the specified Standards/Requirements in all the areas of focus with additions documented below in the Regional Risks and Associated Reliability Standards section.

FRCC also considered the following risk elements and identified additional Standards/Requirements for monitoring as detailed below in the Regional Risks and Associated Reliability Standards section.

- **Number and type of registered functions**
  As of September 24, 2014, FRCC has sixty-eight (68) registered entities.[13] The FRCC Regional Entity is registered as a Reliability Coordinator and Planning Coordinator. The SERC Regional Entity organization is the Compliance Enforcement Authority for these functions.

  The FRCC has not identified any region-specific risks associated with the number and type of registered functions within the FRCC, and therefore has not included additional Reliability Standards due to registered functions.

- **Geographic location such as seasonal/ambient conditions and terrain**
  The area of the State of Florida that is within the FRCC Region is peninsular Florida east of the Apalachicola River. Areas west of the Apalachicola River are within the SERC Region. The entire FRCC Region is within the Eastern Interconnection and is under the direction of the FRCC Reliability Coordinator.

  The FRCC considers factors such as its susceptibility to tropical storms and hurricanes when selecting additional Reliability Standards for inclusion in its monitoring activities. Such storms increase the probability of the region experiencing transmission line vegetation contact, significant imbalances in generation and load, the need to evacuate control centers, and the need to implement restoration plans. As a result, requirements of the Reliability Standards for Loss of Control Center Functionality, Transmission Vegetation Management, and Automatic Underfrequency Load Shedding have been added.

- **BPS transmission lines (circuit miles, voltage levels, IROL flowgates)**
  The FRCC has not identified any region specific risks associated with the BPS transmission lines located in the FRCC region, and therefore has not included additional Reliability Standards due to BPS transmission lines.

- **BPS generation facilities**
  The FRCC has not identified any region specific risks associated with the BPS generation facilities located in the FRCC region, and therefore has not included additional Reliability Standards due to BPS generation facilities.

- **Blackstart Resources**
  Requirements of the Reliability Standard for System Restoration from Blackstart Resources are already included in NERC's risk elements results. Therefore, no requirements have been added.

- **Interconnection points and critical paths**
  The FRCC region only connects to the Eastern Interconnection on the north side of the region due to its peninsular geography. Therefore, the FRCC considers factors such as susceptibility to system separation when selecting additional Reliability Standards for inclusion in its monitoring activities. As a result of the FRCC's limited interconnection points, and as also mentioned for geographic location previously, requirements of the Reliability Standard for Automatic Underfrequency Load Shedding have been added.

[13] Registered functions include: Balancing Authority, Distribution Provider, Generator Owner, Generator Operator, Interchange Authority, Load Serving Entity, Planning Authority, Purchasing Selling Entity, Resource Planner, Reserve Sharing Group, Transmission Owner, Transmission Operator, Transmission Planner, and Transmission Service Provider.

- **Special Protection Schemes (SPS)**
  The FRCC considers factors such as any major SPS installed in the FRCC region when selecting additional Reliability Standards for inclusion in its monitoring activities. As a result of a major SPS in the FRCC region, and as also mentioned for geographic location and interconnection points previously, requirements of the Reliability Standard for Automatic Underfrequency Load Shedding have been added.

- **System events and trends**
  The FRCC considers internal system events when selecting additional Reliability Standards for inclusion in its monitoring activities. External events are reviewed and considered in NERC's risk elements. As no major internal events have occurred recently, FRCC has not included additional Reliability Standards due to system events and trends.

- **Compliance history trends**
  The FRCC considers historical compliance trends within the region when selecting additional Reliability Standards for inclusion in its monitoring activities. As a result, requirements of the Reliability Standards for Cyber Security – Electronic Security Perimeter(s), Cyber Security – Physical Security of Critical Cyber Assets, Cyber Security – Systems Security Management, Loss of Control Center Functionality, and Facility Ratings have been added.

3. Regional Risks and Associated Reliability Standards

The table below contains the Regional risk focus areas identified during the Regional Risk Assessment. The table also contains associated Reliability Standards/Requirements to identified risks that may be considered in the Regional compliance oversight plan.

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
Infrastructure Maintenance	The implementation plan for PRC-005-2 will result in PRC-005-1.1b remaining in effect for 2015. Registered entities are likely to have Protection Systems subject to the current version of the standard, as well as the new version. Therefore, monitoring activities for PRC-005 may include both PRC-005-1.1b and PRC-005-2. This is a clarification on FRCC monitoring, and is not a newly identified regional risk element.	PRC-005-1.1b R2
Extreme Physical Events	FRCC's susceptibility to hurricanes increases the risk of a control center event.	EOP-008-1 R6
Extreme Physical Events	FRCC's susceptibility to hurricanes and frequent storms, along with an extended growth season, increases the risk of vegetation related outages.	FAC-003-3 R1, R2, R6 & R7
Extreme Physical Events	The FRCC's peninsular geography along with its susceptibility to hurricanes, limited connections to the Eastern Interconnect and the existence of a significant SPS that could result in islanding increase the risk of an island event occurring.	PRC-006-1 R8 & R9
Compliance History Trends	FRCC has experienced a high number violations with these Standards/Requirements.	FAC-008-3 R2, R3 & R6 CIP-005-3a R2 CIP-006-3c R2 CIP-007-3c R3

4. Compliance Oversight Plan

Self-Certifications

For 2015 compliance monitoring, FRCC will forgo the annual Self-Certification process and replace annual Self-Certification activities with a more focused risk based approach. FRCC will use Self-Certification in a coordinated approach with the other compliance monitoring methods to address the Standards and requirements that represent the greatest risk to the reliability to the Bulk Power System (BPS) based on the registered entities' overall risk assessment. FRCC will follow the guidance in the 2015 ERO CMEP IP, as well as consider results from Regional risks assessments, registered entity inherent risk assessments, etc. FRCC will implement guided Self-Certification for registered entities to Self-Certify compliance with those Standards and Requirements identified through the risk assessment process. The registered entity should provide the methodology and other documentation used for self-assessment to determine the compliance status for those requirements. This "guided" approach will include more information on the expectations of what the registered entity should consider and include in their response to the FRCC.

Reliability Standards monitored through guided Self-Certification will not be included in the 2015 registered entity Compliance Audit scope.

Those responsible entities that do not have any Critical Assets or Critical Cyber Assets under the CIP V3 Standards will not be scheduled for an off-site audit for the CIP Reliability Standards during the CIP Version 5 Transition Period (August 2014 through March 31, 2016). Instead, those Responsible Entities will be monitored via the guided Self-Certification process for the applicable CIP Standards.

In addition, non-BA/TOP registered entities that were initially scheduled for a six-year audit during 2015 will instead be monitored by guided Self-Certifications. This will allow the RAM department time to perform the necessary IRAs and ICEs.

Periodic Data Submittals

FRCC has identified the Reliability Standards and requirements listed in the table below that require Periodic Data Submittals. The Monthly data submittals are due by the 10th of the month for the previous month's data and the Quarterly data submittals are due by the 15th of the month following the previous quarter. All data submittals are to be submitted via the Compliance Tracking and Submittal system (CTS).

For Quarterly submittals for FAC-003-3 R1 and R2, if an entity does not have any Sustained Outage(s) during a respective quarter, they are not expected to submit a quarterly report. In turn, FRCC will advise NERC that there were no Sustained Outages within the quarter. However, entities are expected to submit a FAC-003-3 Event form for ALL Sustained Outages within the quarter in which the event occurs, as specified in the standard. Again, while not specifically required by FAC-003-3, FRCC strongly encourages and appreciates entities' reporting, within 48 hours, all Sustained Outages for Categories 1A&B, 2A&B and 4A&B utilizing the FAC-003-3 Event form. FRCC will be notified when an event is reported by the CTS system and will follow-up accordingly with the submitting entity and NERC.

2015 Periodic Data Submittal Plan	
Standard & Requirement	**Justification**
BAL-001-1 R1, R2	CPS 1 and CPS 2 data collected by applicable registered entities
BAL-002-1 R1	DCS 2 data collected by applicable registered entities
FAC-003-3 R1 and R2	Sustained Outage data collected by applicable registered entities

Compliance Audits

The audit schedule is also located on the FRCC's website here:

https://www.frcc.com/Compliance/FRCCCompliance/ComplianceDocumentLibrary.aspx

2015 Compliance Audit Plan	
NCR #	**Registered Entity**
NCR00004	Beaches Energy Services of Jacksonville Beach (BES)
NCR00021	Florida Keys Electric Cooperative Assn (FKEC)
NCR00023	Florida Municipal Power Pool (FMPP)
NCR00045	Lee County Electric Cooperative, Inc (LCEC)
NCR00057	Orlando Utilities Commission (OUC)
NCR00068	Seminole Electric Cooperative (SEC)
NCR00073	Tallahassee, City of (TAL)
NCR00079	Vero Beach, City of (VERO)

5. Compliance Outreach

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Spring Compliance Workshop	April 14-16, 2015
CIP Compliance Workshop	May 12-14, 2015
Fall Compliance Workshop	November 10-12, 2015
Reliability Standard Webinars	Periodic
CIP Compliance Newsletter	Periodic

CIP Version 5 (V5) Outreach

FRCC will also develop a CIP Outreach Program for the FRCC registered entities to educate and provide transparency on outstanding CIP V5 issues. This outreach may involve NERC staff support, evaluating an entity's V5 progress, proactively addressing V5 related questions and spending additional time assessing V5 readiness during CIP Compliance Audits.

Appendix A2 - Midwest Reliability Organization (MRO) 2015 CMEP Implementation Plan

This Appendix contains the CMEP Implementation Plan (IP) for MRO as required by the NERC Rules of Procedure.

1. Compliance Monitoring and Enforcement

1.3 CMEP IP Highlights and Material Changes

Mitigating Activities for Compliance Exceptions

As part of the Annual Implementation Plan, MRO staff will periodically sample Compliance Exceptions to verify that the mitigating activities have been completed. The sample will come from only those Compliance Exceptions that have been identified by a registered entity as already mitigated, or Compliance Exceptions that have a planned mitigation date that has passed. Also, the Compliance Exceptions sampled are not restricted to the registered entities that have an Inherent Risk Assessment performed on them for 2015.

The periodic sampling may occur at any time, and will be reviewed through informal means, Spot Checks, or during a normally scheduled Compliance Audit. MRO staff are required to document the results regardless of whether a formal or informal review process is used.

All mitigation activities relating to enforcement matters that are filed with regulators will be verified for completion.

2. Regional Risk Assessment Process

Analysis performed by MRO on risks related to the Risk Areas within the Risk Elements resulted in the identification of a list of Requirements determined to provide an initial level of risk mitigation within the MRO region. (Section 3 below contains this list of requirements.) The analysis focused on several areas that have been identified as having a larger impact to reliability, including areas identified within the 2003 and 2011 blackout reports. The Requirements in Section 3 are not considered the only or complete way to mitigate the related risks, but were determined to be a starting point to focus oversight in the MRO region related to these risks. As referenced in Section 4 below, these requirements are subject to guided Self-Certifications in 2015. In addition to this oversight, as part of the Inherent Risk Assessments that will be performed on registered entities, additional Standards and Requirements will be considered and potentially scoped into entity-specific oversight plans.

3. Regional Risks and Associated Reliability Standards

The table below contains the Regional risk focus areas identified during the Regional Risk Assessment process. The table also contains Reliability Standards/Requirements associated with identified risks that may be considered in the Regional compliance oversight plan.

Reliability Standards Subject to Regional Monitoring		
Risk Area	**Justification**	**Associated Standard & Requirement(s)**
Protection System Misoperations	It is important for entities with awareness of a wide area of the BES, to determine those facilities which are most important and require relay loadability attention.	PRC-023-2 R6
Long Term Planning and System Analysis	Planning criteria were called out in the 2003 and 2011 blackout reports.	TPL-002-0b R2

Reliability Standards Subject to Regional Monitoring		
Risk Area	**Justification**	**Associated Standard & Requirement(s)**
Threats to Cyber Systems (risk elements)	It is important to periodically assure that the ESP is secure, even if testing is being done after individual changes. Small changes in networks that seem to have no impact locally can cause changes in the security posture of the overall network.	CIP-005-3a R4
Threats to Cyber Systems (risk elements)	It is important to periodically assure that CCAs are secure, even if testing is being done after individual changes. Small changes in systems that seem to have no impact locally can cause changes in the security posture.	CIP-007-3a R8
Human Error (risk elements)	The issuing of directives is crucial to reliable system operation, as they are performed by those entities that have a wide area view, and are used during times of emergency to alleviate events.	COM-002-2 R2
Monitoring and Situational Awareness	Evaluation of planning and operational criteria was a technical initiative from the 2003 blackout.	FAC-014-2 R2
Monitoring Situational Awareness (risk elements)	Real-time operating tools were called out in the 2003 blackout report as well as the 2011 blackout report.	TOP-002-2.1b R11
Extreme Physical Events	It is important to inspect rights of way to determine if unscheduled maintenance needs to occur, in order to preemptively identify vegetation issues that could cause a fault. Poor vegetation management was a contributing factor to the 2003 blackout.	FAC-003-3 R6
Extreme Physical Events	It is important to complete vegetation management in order to prevent transmission line faults, which can lead to cascading events. Poor vegetation management was a contributing factor to the 2003 blackout.	FAC-003-3 R7
Uncoordinated Protection Systems (risk elements)	The performance of protection systems directly impacts the operation of the BES, therefore coordination of changes to protection systems is crucial to reliability. Improved protection system coordination was a recommendation in the 2011 blackout report.	PRC-001-1 R3
Uncoordinated Protection Systems (risk elements)	The performance of protection systems directly impacts the operation of the BES, therefore coordination of changes to the BES that impact protection systems is crucial to reliability.	PRC-001-1 R5

4. Compliance Oversight Plan

Self-Certifications

For 2015, Self-Certifications will include staff guidance and instructions. These "guided" Self-Certifications will focus more on risk and supporting evidence than the previous annual Self-Certifications. As part of the guided Self-Certification process, registered entities will provide MRO with supporting evidence to substantiate determinations.

These guided Self-Certifications are intended to provide MRO with reasonable assurance of compliance based upon the results of the registered entity's assessment. When appropriate, the guided Self-Certification can be used instead of Compliance Audits or Spot Checks as the monitoring tool for specific

Reliability Standards and Requirements. The overall goal of the guided Self-Certification process is to improve the effectiveness of oversight and increase efficiency by relying on the work of registered entities in meeting compliance requirements.

Part of the process of relying upon the work of others includes MRO performing a review of the work and evidence supporting the guided Self-Certification results. MRO may re-perform the work, in part, in order to verify the accuracy of the Self-Certification determinations. In the event that further substantiation is needed, MRO staff may conduct a random Spot Check of the work or include the applicable Standards and Requirements in a subsequent Compliance Audit. The overall goal of the guided Self-Certification process is to provide reasonable assurance that the entity meets compliance with the applicable Standards and Requirements.

Guided Self-Certifications will be performed over the implementation period (January 1 to December 31) on a quarterly basis for an identified baseline set of high impact Reliability Standards that have been deemed important for reliable operations of the BPS. The intent of the quarterly frequency is to disperse the workload to assure sufficient time for completion and review, and to promote continuous self-monitoring of compliance.

In addition to the quarterly guided Self-Certification schedule, guided Self-Certifications may also be used for lower risk compliance monitoring as a result of Inherent Risk Assessments of registered entities and for lower risk events that could or did negatively impact the reliable operation of the region or systems within the region.

The following list of registered entities have been identified as being on the 2015 Compliance Audit schedule. Additional registered entities, at the discretion of MRO, will also be subject to Inherent Risk Assessments (IRAs). Based on IRA results and any subsequent Internal Control Evaluations (ICE), these additional registered entities may also be subject to a Compliance Audit in 2015.

2015 Compliance Audit Schedule	
NCR #	**Registered Entity**
NCR01030	Southern Minnesota Municipal Power Agency
NCR01013	Minnkota Power Cooperative
NCR01012	Minnesota Power
NCR01003	Manitoba Hydro
NCR10102	Tri-State Generation and Transmission Association
NCR00826	Midcontinent Independent System Operator, Inc.
NCR00952	Wisconsin Public Service Corporation
NCR01033	Upper Peninsula Power Company
NCR01029	Saskatchewan Power Corporation
NCR00818	Madison Gas and Electric

5. Compliance Outreach

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
MRO Newsletter	Six times a year
MRO Hot Topics	Periodically as needed
MRO Operations Conference	Summer 2015
MRO Security Conference	Fall 2015
MRO Compliance and Enforcement Conference	Fall 2015

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Registered Entity-specific conferences and meetings	Periodically as needed

Appendix A3 - Northeast Power Coordinating Council (NPCC) 2015 CMEP Implementation Plan for Entities within the U.S.

This Appendix contains the CMEP Implementation Plan (IP) for the registered entities within the U.S. portion of NPCC as required by the NERC Rules of Procedure.

1. Compliance Monitoring and Enforcement

1.1 CMEP IP Highlights and Material Changes

In January 2015, the NPCC Entity Risk Assessment (ERA) Group was formed within the NPCC Compliance Department to support the NERC Risk-based Compliance Monitoring and Enforcement Program that was developed through the Reliability Assurance Initiative (RAI). The ERA Group is tasked with implementing the NERC Risk-based Oversight Plan Framework, which includes conducting Inherent Risk Assessments (IRAs) for all registered entities and an Internal Controls Evaluation (ICE) for registered entities that agree to have an ICE performed.

The ERA Group will develop procedures, forms, templates, and necessary tools to conduct and document the IRA and the ICE. The scope, monitoring method, and periodicity of compliance monitoring for each registered entity will be determined based on these tools and documentation.

NPCC will continue to implement a cyber-security outreach program that consists of NPCC Subject Matter Experts visiting critical facilities owned by participating entities (participation is voluntary) and assessing the cyber security posture of the control systems that support the operation of these facilities.

NPCC will continue the physical security outreach program in 2015 (participation is also voluntary) and NPCC staff will hold a Security Information Exchange session, which will include entity presentations, at the spring and fall Compliance Workshops.

As part of the CIP Version 5 transition and consistent with NERC guidance, NPCC will perform CIP audits based on the entity's selected option for maintaining compliance with CIP standards during the Transition Period:

Continue to comply by maintaining a valid RBAM for Critical Asset identification pursuant to CIP-002-3.	Option 1
For Responsible Entities that have already adopted the CIP V4 Critical Asset Criteria (CIP-002-4, Attachment 1), use the CIP V4 Critical Asset Criteria in its entirety, with the exception of criterion 1.4 (Blackstart Resources) and criterion 1.5 (Cranking Paths), to identify assets subject to the controls in CIP-003-3 through CIP-009-3.	Option 2
Use the CIP V5 "High" and "Medium" Impact Rating Criteria (CIP-002-5.1, Attachment 1) to identify assets subject to the controls in the CIP V5 Standards.	Option 3

The on-site CIP Audits will be conducted as directed in the Guidance document. CIP Audits of those entities that have not chosen to move to Version 5 (Options 1 and 2) will be audited to Version 3. If an entity indicates that they have adopted CIP Version 5 (Option 3), NPCC will review their compliance with Version 5 Standards. In all cases, NPCC's approach would be to perform a review of those Standards / Requirements that are "mostly compatible" with the Version 5 Standards. Since Version 3 is enforceable until July 1, 2016, no findings of non-compliance with Version 5 Standards will be issued. A non-public document will be issued indicating any areas of concern where future compliance with version 5 may be in jeopardy.

Previously, off-site CIP audits had been conducted to verify that an entity does not have any Critical Cyber Assets. In accordance with the recently released CIP Transition Guidance, there are no off-site CIP audits scheduled in 2015. NPCC may include selected Spot Checks in place of the Off-site CIP Audits.

NPCC has provided more details on the CIP transition to Version 5 of the Reliability Standards in a webinar that was conducted on March 24 and 25, 2015. Additional information will be presented at NPCC Compliance Workshops, and at a second CIP V5 Transition Seminar to be conducted in the third quarter.

1.2 Other Regional Key Initiatives & Activities

NPCC will continue to participate in the Risk Based Registration Advisory Group (RBRAG) which is charged with the ERO-wide development of criteria for risk-based registration.

NPCC will continue to participate in the **Risk-based Compliance and Enforcement Advisory Group (RBCEAG)** which is monitoring and ensuring the uniform ERO-wide implementation of RAI monitoring and enforcement activities.

NPCC will look to expand the Self-logging of Minimal Risk Issues program to include additional registered entities. In addition, NPCC will also utilize the Compliance Exceptions program for minimal risk violations. The use of these two programs will expedite the processing of minimal risk violations. Therefore, resources will be freed up to more efficiently process more severe violations.

NPCC will continue to be a member of the RAI Regional Entity Group (RAIRE), which is formulating the overall RAI Training and ICE protocol and guidance documents.

NPCC supported all six Webinars associated with the NERC Compliance Auditors Handbook and ERO Checklist. NPCC will continue to provide input to the NERC Manual Task Force (MTF) tasked with maintaining the Auditors Handbook and enhancing Auditor Tools.

NPCC will continue to participate in the development of a program to implement CIP-014-1, Physical Security.

NPCC will continue to participate in the NERC CIP Version 5 Transition Guidance workgroup.

As part of the Events Analysis process, NPCC will continue to encourage registered entities to perform a voluntary, systematic Compliance Analysis (CA) in response to all system events and disturbances. Registered entities are also expected to share the CA with the RE for all Category 2 and above events.

NPCC will continue to participate in ERO Compliance Workshops presenting the NPCC implementation of the Risk-based Compliance Framework and providing support to special ERO presentations (NERC Small ICE Exercise).

2. Regional Risk Assessment Process

NPCC's Regional Risk Assessment Process is a summary and compilation of specific parts of NPCC's Entity Inherent Risk Assessment process and NERC's IRA Assessment Guide that takes into account the nine areas of focus for 2015 consideration.

1. Infrastructure maintenance
2. Uncoordinated protection systems
3. Protection systems misoperations
4. Workforce capability
5. Monitoring and situational awareness
6. Long term planning and system analysis
7. Threats to cyber systems
8. Human error
9. Extreme physical events

NPCC's Regional Risk Assessment Process includes the following:

2.1 Functional Registration Impact Profile

The Functional Registration Impact Profile is used to populate NPCC's standards subject to Regional monitoring. It considers the potential effect on the reliability of the Bulk Power System (BPS) based on NPCC's Regional perspective and registered entity's functions. The following table shows the initial impact classification of registered entities.

Assignment of Initial Functional Registration Impact		
High Impact	**Medium Impact**	**Low Impact**
RC/BA	TO w/o BES facilities	GO/GOP under 200 MW
TOP	GO /GOP between 200 MW and 500 MW	DP peak load under 1000 MW
TO w/ BES facilities	DP peak load over 1000 MW	
GO /GOP over 500 MW		

2.2 NPCC Regional Compliance History

NPCC will examine the past compliance history of the entire Region. This will include an identification of the Standards and Requirements that have been violated the most within the NPCC Region. It will examine past audit performances, including the number and type of violations that were discovered through audits compared with the number and type of violations that were discovered through self-reports or Self-Certifications. It will also incorporate any issues or problems that may have been identified that did not result in a potential violation.

2.3 NPCC Regional Enforcement History Profile

NPCC will analyze violations to identify any trends regarding:

- Level of risk to the **BES** (operational vs. documentation)
- Timeframes of violations (real time, next day, planning)
- Number of repeat violations

2.4 NPCC Overall Evaluation

Based on a registered entity's function, NPCC will specifically examine impact and violations based on the following:

- RC
  - Qualifying IROL/SOL events
  - Qualifying loss of load events
- BA
  - DCS Performance (ACE or restoration of reserve)
  - Qualifying IROL/SOL events
  - Qualifying loss of load events
- TO/TOP
  - Qualifying IROL/SOL events
  - Protection System Misoperations
  - Qualifying loss of load events
- GO
  - Protection System Misoperations

3. Regional Risks and Associated Reliability Standards

The table below contains the Regional risk elements identified during the Regional Risk Assessment. The table also contains associated Reliability Standards/Requirements to identified risks that may be considered in the Regional compliance oversight plan.

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
Uncoordinated Protection Systems; Protection System Misoperations; Monitoring and Situational Awareness	NPCC identified three risk elements where it was necessary to develop a Regional Standard to ensure that applicable entities had Disturbance Monitoring Equipment and capabilities to monitor and capture adequate disturbance data to facilitate Bulk Electric System event analyses.	PRC-002-NPCC-01
Infrastructure Maintenance	Basic capability required to manage reliability during emergency conditions	FAC-003-3 R1,R2,R4,R5,R6,R7
Uncoordinated Protection Systems	Basic capability required to manage reliability during emergency conditions NPCC reliability area of focus in 2015	PRC-006-1 R8,R9,R10 PRC-015-0 R1 PRC-005-1.1b R1,R2 **PRC-023-3 R2[14] to R6**
Workforce Capability	NPCC reliability area of focus in 2015 Basic capability required to manage reliability during emergency conditions Process is critical to maintaining the power system equipment capability/reliability	IRO-005-3.1a R6,R7 TOP-002-2.1b R5,R6,R7,R8,R10,R14 TOP-008-1 R1,R2,R3 TOP-007-0 R1 to R4 VAR-002-2b R1 to R3
Monitoring and Situational Awareness	Basic capability required to manage reliability during emergency conditions Conditions/equipment/capability to perform the functions can change as technology changes NPCC reliability area of focus in 2015	BAL-001-1 R1 to R4 BAL-002-1 R1 to R6 BAL-003-0.1b R2,R3,R5 COM-001-1.1 R1,R2 IRO-005-3.1a R9,R12 IRO-009-1 R3

[14] Removed R1. Already part of NERC Table 3, Protection System Misoperations

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
Long Term Planning and System Analysis	NPCC reliability area of focus in 2015 Basic capability required to manage reliability during emergency conditions	MOD-001-1a R2 to R5 and R7 to R9 MOD-029-1a R1 to R8 **TPL-003-0b R2[15] to R3**
Human Error	Basic capability required to manage reliability during emergency conditions	PER-003-1 R2
Extreme Physical Events	Basic capability required to manage reliability during emergency conditions	**EOP-001-2.1b R6[16]** EOP-002-3.1 R1,R3,R5 EOP-005-2 R2

4. Compliance Oversight Plan

The specific list of audited standards will be contained in the entity's audit notification letter sent at least 90 days prior to the scheduled audit.

The specific list of 2015 monitored standards and the monitoring method will be documented in the registered entity's Compliance Oversight Plan based on Inherent Risk Assessments and Internal Controls Evaluations (if any). Monitoring methods include Audits, Spot Checks, and Guided Self-Certifications.

NPCC will not audit Interchange Authorities, Load Serving Entities or Purchase-Selling Entities in 2015.

The audit schedule is also located on the NPCC's website here:
https://www.npcc.org/Compliance/Audit%20Schedule/2015%20Preliminary%20Audit%20Schedule.pdf

Audits of Canadian Entities will be conducted in accordance with the appropriate agreements.
The following entities are scheduled for an audit in 2015:

2015 Compliance Audit Plan	
NCR #	**Registered Entity**
NCR07133	**Long Island Power Authority**
NCR07136	**Mass. Municipal Wholesale Electric Company**
NCR07181	**NYSEG**
NCR00124	**Ipswich Municipal Light Department**
NCR07090	**Fortistar North Tonawanda**
NCR07091	**New Hampshire Transmission, LLC**
NCR07101	**Granite Ridge Energy, LLC**
NCR07108	**Huntley Power LLC**
NCR07155	**NB Power**
NCR07111	**Hydro-Quebec Production**
NCR07130	**KIAC Partners**
NCR07132	**Lockport Energy Associates**
NCR07154	**New Athens Generating Company, LLC**
NCR00538	**Astoria Energy, LLC**

[15] Removed R1. Already part of NERC Table 9, Extreme Physical Events

[16] Removed R2. Already part of NERC Table 4, Workforce Capability

2015 Compliance Audit Plan	
NCR #	Registered Entity
NCR00006	Calpine Corporation
NCR07026	Capitol District Energy Center Cogeneration Associates, JV
NCR07141	Middletown Power LLC
NCR11121	GenOn East 1
NCR00200	Dynegy Power, LLC
NCR07087	Flat Rock Windpower L.L.C.
NCR11287	Marble River LLC
NCR11324	Brookfield White Pine Hydro, LLC
NCR11337	ReEnergy Black River
NCR11339	Lakeside New York LLC
N/A	Canadian Hydro Developers
N/A	Caribou Wind Park
NCR11152	Tanner Street Generation, LLC
NCR07110	Hydro-Québec Distribution
NCR07228	Vermont Transco, LLC
NCR07124	ISO-NE
NCR07029	Central Maine Power Company
NCR07180	NSTAR Electric Company
NCR10332	NextEra Energy Resources, LLC
NCR07128	National Grid Generation LLC
NCR07220	TransCanada Hydro Northeast Inc
NCR07124	ISO-NE
NCR00088	TC Ravenswood Services Corp.
NCR00543	TC Ravenswood LLC
NCR04057	Exelon Generation Co., LLC (Power)
NCR07133	Long Island Power Authority

5. Compliance Outreach

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
NPCC utilizes its semi-annual workshops as a primary mechanism for outreach to its registered entities. An Introduction to NPCC presentation is included at each workshop. NPCC conducts webinars open to all NPCC registered entities on an as needed basis. It also posts webinar question-and-answer documents as appropriate. NPCC responds to individual requests from registered entities, but if an individual concern can be applied to all registered entities, NPCC will post a Compliance Guidance Statement or clarification to address that concern. NPCC conducts surveys of its registered entities as needed to acquire registration data, BES element data, workshop content preferences, etc. NPCC hosts monthly Compliance Committee meetings to disseminate the latest information regarding the compliance program to industry stakeholders. In 2013, NPCC implemented a Physical Security Outreach Program. Under this continuing program, NPCC physical security subject matter experts perform voluntary physical security assessments for certain registered entities. NPCC developed a Cyber Security Outreach Program that began in 2014 and will continue in 2015. In 2015, NPCC **has instituted** a CIP Version 5 transition outreach program, **consisting of Seminars and on-site assessments of Version 5 Transition activities.** NPCC developed an internal entity guide to assist registered entities in meeting quarterly reporting requirements pursuant to PRC-004 and NERC ALR4-1. **NPCC developed a separate processing method and reporting template for Special Protection System (SPS) operations and misoperations, per request from NERC, pursuant to PRC-016 and ALR4-1.** The NPCC website includes links associated with the areas of Standards, Registration, Compliance Monitoring, Enforcement, and **ERA.**	2015 workshop dates: May 19-21 and Nov 17-19.

Appendix A4 - ReliabilityFirst Corporation (ReliabilityFirst) 2015 CMEP Implementation Plan

This Appendix contains the CMEP Implementation Plan (IP) for ReliabilityFirst as required by the NERC Rules of Procedure.

1. Compliance Monitoring and Enforcement

1.1 CMEP IP Highlights and Material Changes

ReliabilityFirst will follow and implement the ERO Risk-based Compliance Oversight Framework described in the ERO CMEP IP. The 2015 ERO CMEP Implementation Plan identifies a number of risk elements and areas of focus, which provide a starting point for ReliabilityFirst's risk analysis and Compliance Oversight Plan. However, the plan recognizes that it does not contain complete set of the risks that may affect the BPS, and that Regional Entities are expected to consider local risks and the specific circumstances associated with individual registered entities within their footprint when developing their compliance oversight plans.

As such, ReliabilityFirst performed its Regional Risk Assessment (RRA), which identified areas of focus specific to the ReliabilityFirst region (ReliabilityFirst areas of focus), set forth in Section 3 of this document. ReliabilityFirst may monitor the Reliability Standards (Standards) and Requirements associated with the ReliabilityFirst risk elements in 2015. ReliabilityFirst has the discretion to add, subtract, or modify Standards and Requirements as it deems necessary based on the individual Inherent Risk Assessments (IRA).[17] The ReliabilityFirst RRA is discussed in further detail in Section 2 of this document.

CMEP Implementation Plan Updates and Changes throughout the Year

ReliabilityFirst monitors FERC and NERC activities, system events, and events in the ReliabilityFirst region. Based on these monitoring activities, ReliabilityFirst may modify its CMEP Implementation Plan throughout the year to include Standards that address and mitigate situational awareness and reliability issues as they arise.

1.2 Other Regional Key Initiatives & Activities

Risk-based Enforcement

ReliabilityFirst is implementing a risk based enforcement approach consistent with that of the ERO Enterprise. Specifically, ReliabilityFirst will be exercising enforcement discretion by processing qualified minimal risk issues as "compliance exceptions." Compliance Exceptions will effectively supersede the Find, Fix, Track and Report ("FFT") disposition method for most minimal risk noncompliance.

Self-Logging

ReliabilityFirst is implementing self-logging approach consistent with that of the ERO Enterprise. Self-logging allows qualified registered entities to keep a log of minimal risk noncompliance that is periodically checked by ReliabilityFirst instead of submitting individual self-reports and corresponding mitigation plans for each noncompliance. Once ReliabilityFirst approves the log entries, they are processed as compliance exceptions.

2. Regional Risk Assessment Process

The RRA identifies risks within the ReliabilityFirst region that could potentially impact the reliability of the BPS. To accomplish the RRA, ReliabilityFirst utilizes a cross-functional team of internal Subject Matter Experts (the RRA Team) to review and analyze information and data to determine the highest-priority risks to the ReliabilityFirst region. The types of region-specific information and data the RRA Team reviews includes: US Population & Census Data, Severe Weather Related Outages (*e.g.,* OE-417 reports, Outages), Generation

[17] Additionally, ReliabilityFirst audit teams have the discretion to adjust audit scope during an engagement at a registered entity.

Availability Data System (GADs), Transmissions Availability Data System (TADS), Misoperations, Event Analysis, Load Analysis, Locational Marginal Pricing, System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), TIER Power Line Ranking, Interconnection Points, Cyber Security data, Physical Security data, and data on Threats and Vulnerabilities. After a period of information gathering, analysis and decision making, the RRA team develops the results of the RRA in the form of ReliabilityFirst risk elements.

The 2014 ReliabilityFirst RRA identified the following five ReliabilityFirst risk elements *(in no particular order or ranking)*:

- Weather Related
- Physical Threat
- Cyber Security
- Human Error
- Equipment Failure

The five ReliabilityFirst risk elements align with five of the nine NERC risk elements discussed in the 2015 ERO CMEP Implementation Plan:

- Infrastructure Maintenance
- Workforce Capability
- Threats to Cyber Systems
- Human Error
- Extreme Physical Events

ReliabilityFirst believes that the four NERC risk elements that do not align with ReliabilityFirst risk elements, set forth below, are best assessed at the registered entity level during the Inherent Risk Assessment (ReliabilityFirst's Entity Risk Assessment):

- Uncoordinated Protection Systems
- Protection System Misoperations
- Monitoring and Situational Awareness
- Long Term Planning and System Analysis

Section 3 of this document contains additional detail on the five ReliabilityFirst risk elements and their Reliability Standards and Requirements, which ReliabilityFirst may include in the 2015 ReliabilityFirst Compliance Oversight Plans.

The RRA is performed annually and will be updated as necessary. As new and emerging threats and risks are identified, system events take place, and compliance monitoring activities are performed, ReliabilityFirst will update the RRA to keep current with potential issues, threats and risks.

ReliabilityFirst reviews potential risks posed by an individual registered entity to the reliability of the BPS, by utilizing the IRA – Inherent Risk Assessment guide developed as part of the RAI Initiative. This assessment helps identify areas of focus and the level of compliance oversight required. Reliability Standards and Requirements may be added to or removed from the scope of an audit. Going forward, ReliabilityFirst will perform risk assessment prior to each audit, and at least two weeks prior to the development of a registered entity's audit notification package.

In additional to the risk elements and focus areas identified in the RRA, ReliabilityFirst identified Region-specific risk factors that it will consider when evaluating a registered entity. The items below provide Region-specific details on additional risk areas that ReliabilityFirst may consider when identifying and assessing risk.

- Population and geographic location – The ReliabilityFirst region includes three of the most populated areas in the United States (Chicago, Philadelphia, and Washington DC). The ReliabilityFirst region also contains many medium-sized urban areas such as Baltimore, Cleveland, Pittsburgh, Indianapolis, Cincinnati, and Toledo. Maintaining and ensuring reliable service to these areas of the country is critical to the overall well-being of the nation and national security. Any registered entity serving the load in these areas and those registered entities responsible for operating and maintaining reliability of the BPS supplying these areas, or in close proximity to these populated areas, may pose a higher risk.

- Entity Make-up and diversity – The ReliabilityFirst region is a summer peaking region, with several registered entities serving peak loads or operating an individual resource in excess of 500 MWs. Maintaining and ensuring reliable service to these areas of the country is critical to the well-being of the people and in some cases to national security.

- Entity Registration – ReliabilityFirst takes into account Entity Registration (i.e. RC, BA, TOP versus DP, PSE), during the assessment of registered entities. RCs, BAs and TOPs have the authority to issue operating orders, instructions, and directives and ultimately play a larger role in safeguarding the reliability of the BES.

- Transmission Assets – The transmission network in the ReliabilityFirst region consists of 765kV; 500kV; 345kV; 230kV; 138kV and 115kV lines. The majority of transmission facilities are overhead, with large urban areas serviced by underground transmission cables. Overall asset ownership (lines, transformers, generators, voltage, size of units, fuel type, flowgates, SOL, IROL, etc.) are also considered as part of the assessment. These assets form the backbone of the system and will be assessed with a higher risk due to their importance to maintain the reliability of the BPS. A registered entity that owns these types of facilities may have their audit scope adjusted to address owning and maintaining these types of equipment.

- Misoperations – the number of misoperations within the ReliabilityFirst region has been an issue of focus over the last few years. There is a higher risk to the BPS if the cause for a misoperation is due to controllable circumstances. Registered entities having these types of misoperations may have their audit scope adjusted to address resolving these misoperations.

- Special Protection Schemes and Relay Protection – registered entities in the ReliabilityFirst region use special protection schemes to mitigate system constraints until transmission reinforcements can be planned and built. In some cases these special protection schemes are left in place indefinitely. Special protection schemes can present a higher risk to the BPS when they are not properly implemented, coordinated, or operated as intended.

- Emergency Operations and Blackstart Facilities – There are multiple facilities designated as blackstart units in the ReliabilityFirst region. Registered entities are required to regularly test these blackstart units and submit results to ReliabilityFirst annually. There is a potential risk that there may be insufficient blackstart resources designated for an area, or that blackstart resources may not be available if they are not properly tested.

- Generation Assets – ReliabilityFirst generation mix is made up of units that are nuclear, coal, gas, hydro, wind, solar, and refuse power assets. The asset mix for the next few years is expected to change, with a decrease in coal generation and an increase in renewable resources such as wind generation and solar generation. There is a risk that generating capacity and available resources may not be available to meet demand on a real-time, near term and long term time horizon. Registered entities owning these

resources may be subject to standards and requirements to ensure availability and proper maintenance of these resources is retained.

- EMS and Monitoring Tools Availability – Keeping monitoring tools available and operational for system operators' use is imperative to maintaining a reliable grid. Registered entities with these types of monitoring tools may have additional Standards and Requirements in their audit scope to ensure these monitoring tools are maintained and available to the system operator.

The non-physical characteristics considered by ReliabilityFirst during the IRA include the following:

- Operating Performance – ReliabilityFirst analyzes data from the GADS, TADS reports and information from reviewed system events. Since 2008 there have been various system events ranging from local load drop to interconnection frequency excursions. There is always a risk that an event could cause a large scale blackout, but it is more probable that a series of smaller events will occur and if undetected, will manifest into a larger event. This information can help to pinpoint problems or identify trends for a registered entity and help to focus the scope of an audit to deter future events from occurring.

- Compliance History – Assessing the violation history, audit performance, Self-Certification, and self-report performance indicates past performance trends and a registered entity's behavior towards compliance and their implementation of their compliance programs. Registered entities with a history of compliance issues may have their audit scope adjusted to ensure their mitigating measures achieve full compliance and prevent recurrence.

- Normal System Performance – The flow of power across the ReliabilityFirst region is normally from west to east, to supply the beltway of the mid-Atlantic region and northeast (including the New York City Area). There are instances when this normal power flow is disrupted and system constraints are realized. These system constraints rely on operator intervention for resolution. A registered entity's system events (involvement, impact to BPS, significance, availability of operators tools, EMS, etc.), their operational performance (use of Emergency procedures and why), and their overall situational awareness all play a role in their system performance.

- System Maintenance upkeep and replacement (EMS, Physical plant, age of equipment, record keeping, tracking, and overall program) Continued maintenance of equipment is essential to a reliable BPS. As equipment gets older, system maintenance may increase and facility availability may decrease.

Additionally, where ReliabilityFirst has confidence in a registered entity's internal compliance program as a result of an Internal Control Evaluation (ICE), ReliabilityFirst may narrow the audit scope and audit periodicity to reflect the compliance maturity of the registered entity. To support a strong culture of compliance and to demonstrate robust internal controls, registered entities are encouraged to continually perform self-assessments of their compliance program and internal controls on an ongoing basis.

ReliabilityFirst will notify registered entities of the Reliability Standards and Requirements to which they will be monitored against through the posting of the CMS for Self-Certification and Data Submittals, the Compliance Monthly Update Letter, the audit notification packages, as well as any of the outreach programs listed in Section 5 of this document.

3. Regional Risks and Associated Reliability Standards

The table below contains the ReliabilityFirst risk focus areas identified during the ReliabilityFirst RRA. The table also contains the Reliability Standards and Requirements associated with each risk element.

NOTE: Standards and/or Requirements in **BLUE** denote inclusion within the NERC risk elements identified in the 2015 ERO CMEP IP.

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
Weather Related (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. **2014 Cold Weather Event**: As a result of this event, there is a need to: (1) determine that entities investigate a process for unit testing and preparation of resources in advance of winter operations, including testing dual-fuel capability**,** (2) review operator communications with respect to fuel-limited generation commitment decisions for accuracy and consistency, (3) changes to allow adjustment of start times based on changes in fuel utilized, (4) requirements for generation units whose primary fuel may not be natural gas but that require gas to operate, (5) review the entities emergency procedures to ensure overall communications and coordination of emergency procedures, (6) ensure transmission owners understand their existing voltage reduction capabilities (amount, time frame, etc.), (7) have the entities consider adjustments to the roles and responsibilities for communications during emergency procedures besides refining the training to reinforce processes and tools.	EOP-001-2.1b R4 TOP-001-1a R5 TOP-001-1a R4 PER-005-1, R1.1.1
Weather Related (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. Attachment 1-TOP-005 lists the types of data that BAs and TOPs are expected to share with other BAs and TOPs. Item 2. Other operating information updated as soon as available. Item 2.8. Severe weather, fire, or earthquake. There is a continual need to ensure that the conditions of Item 2.8 are met per R2.	TOP-005-2a R2
Weather Related	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements,	EOP-003-2 R1,R3,R5,R8 TOP-002-2.1b R5,R6,R7

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
(Aligns with ERO risk element: *Extreme Physical Events)*	ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. **2013 Hot Weather Event.** Several days of unusual, extremely hot weather led to emergency conditions in an RC service area. In order to avoid more serious impacts, the RC had to direct transmission owners to implement controlled outages in a few contained areas for limited time periods. Controlled outages such as these are a last resort to prevent uncontrolled blackouts over larger areas **(SEE EOP-003-2, R1, R3, R5 & R8).** During this period, temperatures were approximately 20 degrees above normal, and demand for electricity reached an all-time high. At the same time, some generation and transmission facilities were scheduled out of service for routine maintenance because lower system demand was usually experienced during this period **(SEE TOP-002-2.1b, R5, R6 & R7).**	
Weather Related (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. **2012 Hurricane Sandy Event.** Some TO/DP entities in the RTO, particularly those that were not on the coast, experienced greater damage in other storms, such as the 2012 Derecho storm. However, the damage that others experienced from Hurricane Sandy exceeded that caused by both Hurricane Irene and the Derecho storm. In fact, one entity reported that Sandy was the most damaging storm to them since record keeping began. For one entity, all service areas were impacted. The majority of increased staffing was in the restoration area. Additional areas that received increased staffing were operations centers, primary control centers, and backup control centers. **1.** A large NPGOP had only one nuclear station that was damaged due to the loss of transmission system load and experienced high voltage. Another nuclear facility had a temporary loss of off-site power due to switchyard damage and a bushing on a voltage regulator associated with a transformer. During loss of off-site power at this facility, the reactor shutdown	BAL-005-0.2b R7 COM-001-1.1 R3,R5 EOP-001-2.1b R4 EOP-005-2 R1, R1.2 NUC-001-2.1 R7,R8,R9.4,R9.4.1-3 TOP-001-1a R4,R5 TOP-002-2.1b R7

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
	cooling and spent fuel cooling was temporarily lost but was restored when emergency diesels started and loaded. Fossil units were forced off both pre-storm (in anticipation of potential flooding) and as the stations flooded. **2. Five potential lessons learned were identified for generation stations during the storm:** • ISOs/RCs need to improve communication with generation plants during major events. • ISOs/RCs should develop or document alternate communications methods when normal methods are lost. • More comprehensive weather preparation procedures need to be developed. • Improvements can be made for managing personnel who remain on-site. • Development of anticipated generation reductions is necessary for the loss of one or more nearby transmission elements. **3. Several generation operation risks were identified during the storm. These include:** • Increased potential for Loss of Off-site Power (LOOP) to nuclear facilities. • Possibility of LOOP due to switchyard damage, or loss of normal condenser cooling and loss of availability of service water due to high water. • Curtailments due to wet coal, which is normal with any significant precipitator. • Potential lack of fuel due to damage to the fuel provider's facilities. **4.** The largest challenge for the BA was coordinating load lost on the distribution systems with lost generation—in particular, the loss of entire generating stations or the loss of multiple units within close temporal proximity. This at times forced ACE to go either high or low for extended periods of time. It was also challenging to maintain load/generation balance during restoration as generation and/or load was added back into the system.	
Weather Related (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. EOP-005-2, R6 & R9: A large TOP has not been audited for these requirements.	EOP-005-2 R6, R9

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
Weather Related (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. EOP-006-2, R1: The two RCs have not been audited for this requirement.	EOP-006-2 R1
Weather Related (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. EOP-010, R1 & R3: Although the results of a GMD are reported under EOP-004-2, means of detection and correction for these types of events will eventually fall under EOP-010 which was recently approved by FERC in June 2014, but has no enforcement date at this time. GMDs are confined to a small eastern portion of PJM. MISO is not significantly impacted by GMDs. PJM addresses GMDs in their Emergency Procedures Manual.	EOP-010-1 R1,R3 (as of 4/1/15)
Weather Related (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. TPL-002-0b, 003-0b & 004.0a: TPs have not been audited for this requirement since 2009 and 2010.	TPL-002-0b R1 TPL-003-0b R1 TPL-004-0a R1
Weather Related (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015.	EOP-001-2.1b R1,R2,R3,R4,R6 EOP-002-3.1 R1,R2,R3,R4,R5 EOP-003-2 R1,R3,R7,R8 EOP-004-2 R2 IRO-003-2 R1,R2 IRO-004-2 R1 IRO-005-3.1a R5,R6,R9 PRC-006-1 R1,R2,R3,R4,R5,R9,R10 PRC-022-1 R1 TOP-006-2 R2,R6,R7 TOP-007-0 R1,R2,R3,R4 TOP-008-1 R1,R2,R3,R4 TPL-001-4 R1, R7 (as of 1/1/15) TPL-002-0b R1

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
		TPL-003-0b R1 TPL-004-0a R1 VAR-002-2b R2,R3 (v3 as of 10/1/14)
Physical Threat (Aligns with ERO risk element: *Extreme Physical Events)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. In CIP-006-3, failure to comply with the requirements of this standard can lead to threats in cyber and physical security space.	CIP-006-3c R1,R2,R3,R4,R5,R6,R7,R8
Cyber Security (Aligns with ERO risk element: *Threats to Cyber Systems)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. Access control is defined by CIP-004-3a, R4. In CIP-005-3a, CIP-006-3c & CIP-007-3a, failure to comply with the requirements of these standards can lead to threats in cyber and physical security space.	CIP-004-3a R4 CIP-005-3a R1,R2,R3,R4,R5 CIP-006-3c R1,R2,R3,R4,R5,R6,R7,R8 CIP-007-3a R1,R2,R3,R4,R5,R6,R7,R8,R9
Human Error (Aligns with ERO risk element: *Human Error & Workforce Capability)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. A medium size entity had an established procedure that required a series of communications in advance of energizing new equipment to assure ratings information is timely updated. It was determined that procedure was not strictly followed for two projects and resulted in a communication gap between the project team and the groups responsible for updating and communicating the facility ratings.	FAC-008-3 R8
Human Error (Aligns with ERO risk element: *Human Error & Workforce Capability)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. Due to reconfiguration at a substation for breaker installation and relay replacement by a TO, a line outage resulted in disabling of the primary and backup	IRO-010-1a R3

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
	protection on an energized bus. The implications of removing the 138 kV line facilities and the change in protection status of the bus was not recognized by field personnel. As a result, the system operator was not informed of the disabling of bus protection during the outage resulting in this information not being communicated to the RC.	
Human Error (Aligns with ERO risk element: *Human Error & Workforce Capability)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. An oversight in an medium size entity's Generator Protection System Maintenance and Testing Program which required testing of relays that were changed, their associated control circuitry paths, as well as all of the other input paths of the associated lockout relays resulted in these devices not being tested.	PRC-005-1.1b R3 (v2 as of 4/1/15)
Human Error (Aligns with ERO risk element: *Human Error & Workforce Capability)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. A large entity's Out-of-Step Blocking (OSB) Relay Loadability Spreadsheet contained an error in the formula used to calculate certain OSB relay loadability values.	PRC-023-2 R2 (v3 as of 10/1/14)
Human Error (Aligns with ERO risk element: *Human Error & Workforce Capability)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. A large registered entity recently failed to recognize they had entered an unknown operating state when extremely low substation battery voltage was intermittently occurring which compromised the relay protection at the substation.	TOP-004-2 R4
Human Error (Aligns with ERO risk element: *Human Error & Workforce Capability)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015.	

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
	A small GOP identified that they had exceeded their voltage schedule without making notification to the TOP. It was determined that the Control Room Operator failed to recognize the elevated voltage condition in spite of received alarms, operator aids, and training. Another small GOP was unaware of their obligation to notify the TOP when their assigned voltage schedule could not be met. Following a planned outage, a Power System Stabilizer (PSS) status change was not reported within the required 30 minutes. The exciter went through a control upgrade during the outage and during the course of the project, the PSS was disabled. The cause was determined to be an oversight of the operator due to not verifying the PSS was in service during start up due to past routine sequence. A large GOP on numerous occasions, exceeded their voltage schedules at various generating facilities due to lack of operator situation awareness of the AVR status.	VAR-002-2b R2 (v3 as of 10/1/14) VAR-002-2b R3, R3.1 (v3 as of 10/1/14)
Human Error (Aligns with ERO risk element: *Human Error & Workforce Capability)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015.	CIP-004-3a R1,R2 COM-002-2 R2 EOP-001-2.1b R2,R3,R4 EOP-003-2 R8 EOP-005-2 R10,R11,R17 EOP-006-2 R9,R10 PER-005-1 R3
Human Error (Aligns with ERO risk element: *Human Error & Workforce Capability)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. In CIP-002-3 - CIP-009-3, there is a possibility of Human Error associated with any of the requirements in these standards.	CIP-002-3 R1,R2,R3, R4 CIP-003-3 R1,R2,R4,R5,R6 CIP-004-3a R1,R2,R3,R4 CIP-005-3a R1,R2,R3,R4,R5 CIP-006-3c R1,R2,R3,R4,R5,R6,R7,R8 CIP-007-3a R1,R2,R3,R4,R5,R6,R7,R8,R9 CIP-008-3 R1,R2 CIP-009-3 R1,R2,R3,R4,R5
Equipment Failure (Aligns with ERO risk element: *Infrastructure Maintenance)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. Per the Compliance Monitoring Section of this standard, Each BA shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating	BAL-006-2 R4.3

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
	Committee to determine the BA's Interchange error(s) due to *equipment failures or improper scheduling operations, or improper AGC performance. Note: *ReliabilityFirst wishes to determine if the number of equipment failures that impact AIE is presently known.	
Equipment Failure (Aligns with ERO risk element: *Infrastructure Maintenance)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. During relay testing, a large registered entity recently failed to report a relay failure which would not initiate a breaker trip and thus reduced system reliability for twelve days. The equipment failure and reduced reliability was not reported to the respective entities. It is also believed that this entity had entered an unknown operating state per TOP-004-2, R4.	PRC-001-1.1 R2, R2.2
Equipment Failure (Aligns with ERO risk element: *Infrastructure Maintenance)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. A large registered entity recently failed to recognize they had entered an unknown operating state when extremely low substation battery voltage was intermittently occurring which comprised the relay protection at the substation. The condition was not studied or analyzed to determine any possible impacts to the reliability of the BES.	TOP-004-2 R4
Equipment Failure (Aligns with ERO risk element: *Infrastructure Maintenance)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. A medium-size entity experienced an ECS failure which resulted in loss of monitoring and control capabilities due to failure of their front-end processors. It's RC and neighboring TOPs were only able to monitor the tie-lines. During an ECS outage while the TOCC asked neighboring TOPs to monitor tie lines, the TOCC could not monitor the applicable transmission line status, real and reactive power flows, voltage, and status of rotating and static	TOP-006-2 R1 TOP-006-2 R2

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
	reactive resources. Also, the TOCC did not have control to operate the system during the ECS outage	
Equipment Failure (Aligns with ERO risk element: *Infrastructure Maintenance)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015.	FAC-003 R1,R2,R3,R4,R5,R6,R7 PRC-005-1.1b R3,R4 (v2 as of 4/1/15) PRC-008-0 R1,R2 PRC-011-0 R1 PRC-017-0 R1
Equipment Failure (Aligns with ERO risk element: *Infrastructure Maintenance)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. CIP-008-3 requires an Incident Response Plan for Critical Cyber Assets. Lack of such a plan, in the event of an incident, will leave the entity with the inability to properly respond to the incident.	CIP-008-3 R1
Equipment Failure (Aligns with ERO risk element: *Infrastructure Maintenance)*	As a result of ReliabilityFirst's review of the NERC risk elements and the ReliabilityFirst risk elements, ReliabilityFirst identifies these Standards and Requirements for compliance monitoring focus in 2015. CIP-009-3 requires a recovery plan for Critical Cyber Assets. Lack of such a plan, in the event of equipment failure, will leave the entity with the inability to properly recover from an event.	CIP-009-3 R1,R2,R3,R4,R5

4. Compliance Oversight Plan

Self-Certifications and Spot Checks

ReliabilityFirst will require Self-Certifications by all registered entities, including those that will be audited in 2015. ReliabilityFirst will require all Self-Certifications to be completed on a Requirement-level basis. ReliabilityFirst will publish a list of the Standards and Requirements to which registered entities must self-certify in the ReliabilityFirst 2015 Compliance Monitoring schedule.

ReliabilityFirst presently has no Spot Checks scheduled for 2015, but reserves the option to initiate Spot Checks throughout the year as needed.[18] In addition, ReliabilityFirst may use the Spot Check process to verify mitigation plans as needed.

Compliance Monitoring Schedule for Self-Certifications and Data Submittals

ReliabilityFirst developed a Compliance Monitoring Schedule (CMS) that contains the Standards and Requirements for the Self-Certifications and Data Submittals scheduled for 2015. The CMS is based upon the NERC risk elements set forth in the NERC 2015 ERO CMEP Implementation Plan and the ReliabilityFirst risk

[18] As part of its oversight of the PJM Local Control Centers, ReliabilityFirst conducts one random spot-check of a Local Control Center each year.

elements set forth in Section 3 below. Several Requirements in the CMS include a data submittal. Most of these data submittals are associated with the monthly, quarterly, and or annual reporting requirements set forth in the Requirements.

In addition to the Self-Certification process in the CMS and using the IRA results, ReliabilityFirst may require certain entities to certify compliance, with supporting evidence, to specific Reliability Standards associated with newly identified or emerging risks. The overall goal is to obtain assurance that, entities, through their compliance with applicable Reliability Standards, have mitigated identified risks to reliability.

CIP Self-Certifications and Data Submittals in Lieu of CIP Audits for Registered Entities with no Critical Assets or Critical Cyber Assets

For registered entities subject to the CIP Standards that own no Critical Assets or Critical Cyber Assets, ReliabilityFirst will perform Self-Certifications and data submittals in lieu of conducting an off-site audit. This determination is based upon NERC's Cyber Security Reliability Standards CIP V5 Transition Guidance which states:

> For those Responsible Entities that do not have any Critical Assets or Critical Cyber Assets under the CIP V3 Standards…Regional Entities will forgo off-site audits of the CIP Reliability Standards during the Transition Period. Regional Entities may instead use compliance monitoring methods, such as Spot Checks, Self-Certifications, among others.[19]

Compliance Monitoring of Purchase-Selling Entity (PSEs)

For registered entities registered for the PSE function, ReliabilityFirst will perform Self-Certifications in lieu of conducting an audit, as their ERAs indicate the need. These Self-Certifications will apply to registered entities that are registered for multiple functions in addition to the PSE function (e.g., if a registered entity is registered as a DP, LSE and PSE, the audit scope will only include Standards and Requirements applicable to the DP and LSE functions, and the registered entity will submit Self-Certifications for the Standards and Requirements applicable to the PSE function). This determination is based on ReliabilityFirst's experience to date and will be reevaluated in future Implementation Plans as needed.20 PSEs are obligated to maintain compliance with applicable Reliability Standards at all times.[21]

Monitoring of New or Revised Standards

ReliabilityFirst will monitor new or revised Standards based upon their implementation plans and as required by NERC and FERC. A list of new and revised Standards and their effective dates is set forth below:

Standards Subject to Monitoring in late 2014	
Standard	**Effective Date**
INT-004-3	10-1-2014
INT-006-4	10-1-2014
INT-009-2	10-1-2014
INT-010-2	10-1-2014
INT-011-1	10-1-2014
PRC-023-3	10-1-2014

[19] NERC Cyber Security Reliability Standards CIP V5 Transition Guidance, Section 5, page 7, http://www.nerc.com/pa/CI/Documents/V3-V5%20Transition%20Guidance%20FINAL.pdf.

20 If the Risk-Based Registration Initiative becomes effective prior to 2015 or ReliabilityFirst otherwise identifies a need to change this approach, ReliabilityFirst will update the Implementation Plan as appropriate.

[21] It should be noted that if the Risk Based Registration initiative becomes effective, there is the possibility that the PSE function may be removed and ReliabilityFirst will no longer require these self-certifications.

PRC-025-1	10-1-2014
VAR-001-4	10-1-2014
VAR-002-3	10-1-2014

Standards Subject to Monitoring in 2015	
Standard	**Effective Date**
BAL-003-1	4-1-2015
EOP-010-1	4-1-2015
MOD-032-1	7-1-2015
PRC-005-2	4-1-2015
TPL-001-4	1-1-2015

The audit schedule will not be posted on the ReliabilityFirst website. If an entity has a question concerning its audit, please contact ReliabilityFirst.[22]

2015 Compliance Audit Schedule	
NCR #	**Registered Entity**
NCR08039	Allegheny Ridge Wind Farm, LLC
NCR00680	American Bituminous Power Partners, L.P.
NCR08077	Wheelabrator Falls Inc.
NCR08034	US Operating Services Company - Chambers
NCR08053	Hancock-Wood Electric Cooperative, Inc.
NCR00941	Washington City Light & Power
NCR00761	Duke Energy Ohio/Kentucky PJM
NCR08001	Bryan Municipal Utilities
NCR00711	City of Batavia Municipal Electric Utility
NCR00748	The Dayton Power and Light Company
NCR08019	East Coast Power Linden Holding LLC
NCR10257	EFS Parlin Holdings LLC
NCR00417	Whiting Clean Energy, Inc.
NCR08013	Commonwealth Edison Company
NCR00917	Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.
NCR11235	Gratiot County Wind LLC
NCR00896	Public Service Electric & Gas Company
NCR00822	Michigan Public Power Agency
NCR11097	TAQA Gen X LLC
NCR00721	City of Rochelle
NCR11247	GSG 6, LLC

[22] As mentioned above, for registered entities where the CIP Standards apply, that have declared that they own no Critical Assets (CAs) or Critical Cyber Assets (CCAs), ReliabilityFirst will perform self-certifications and data submittals in lieu of conducting an off-site audit. This determination is based upon Cyber Security Reliability Standards CIP V5 Transition Guidance provided by NERC.

For those registered entities that are also registered for functions that are audited on a six year cycle, ReliabilityFirst will evaluate and determine the scope of those registered entity audits based upon the risk those functions pose to the BES (i.e. a TOP that is also registered as a LSE, etc.). There may be times when these audits are not conducted based upon the registered entity ERA.

2015 Compliance Audit Schedule	
NCR #	**Registered Entity**
NCR11297	Homer City Generation, L.P.
NCR00794	Hoosier Energy REC, Inc.
NCR00954	Wolverine Power Supply Cooperative, Inc.
NCR11380	Kincaid Generation, LLC
NCR08026	PECO Energy Company
NCR00337	Troy Energy, LLC
NCR00889	PPL Susquehanna, L.L.C.
NCR00884	PPL Electric Utilities Corporation
NCR00940	Wabash Valley Power Association, Inc.
NCR00006/NCR04026/NCR05055	Calpine Corporation
NCR07025/NCR01189/NCR00007/ NCR10115	Calpine Energy Services
NCR10208	Lincoln Generating Facility, LLC
NCR00682/NCR01056	American Electric Power Service Corporation as agent for Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Ohio Transmission Company, AEP Appalachian Transmission Company, AEP West Virginia Transmission
NCR03044	MISO-MBHydro Contingency Reserve Sharing Group
NCR00761	Duke Energy Corporation
NCR00936	University Park Energy, LLC
NCR00826	Midcontinent Independent System Operator, Inc.
NCR00688	Atlantic City Electric Company
NCR00752	Delmarva Power & Light Company
NCR00881	Potomac Electric Power Company

5. Compliance Outreach

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Monthly Newsletter - The ReliabilityFirst Newsletter provides registered entities with news and information relating to reliability activities.	Monthly throughout the year.
Monthly Compliance Update Letter - The ReliabilityFirst Monthly Compliance Update Letter provides registered entities with any changes made to the Compliance Monitoring Schedule and the due dates for compliance submittals.	Updated throughout the year as needed.
ReliabilityFirst Website - The ReliabilityFirst website provides compliance and technical materials to support compliance program implementation.	Monthly throughout the year.
Workshops/Seminars/Webinars - ReliabilityFirst Compliance workshops/seminars or webinars, will be scheduled to assist the registered entities in the understanding of their responsibilities to satisfy compliance to the Reliability Standards throughout the year.	Semi-annual (March and October).
CIP Version 5 Outreach and Awareness – ReliabilityFirst will conduct CIP Version 5 outreach, including training and education engagements, to ensure that registered entities have confidence in their implementation of the CIP V5 Standards and Requirements. These engagements will primarily be conducted as Workshops and Webinars.	Monthly throughout the year.

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Compliance Data Management System (CDMS) - ReliabilityFirst allows its registered entities to report compliance via CDMS, an internet based application. The CDMS home page provides informational announcements, updates, and newsworthy items of interest to the registered entities.	Updated throughout the year as needed.
Periodic Reports - ReliabilityFirst will provide Periodic Reports to its registered entities identifying compliance related activities that the registered entities continue to struggle with. These reports will be posted on the ReliabilityFirst website.	Monthly throughout the year.
Open Compliance Calls - ReliabilityFirst has implemented a monthly conference call to provide an open forum for registered entities to call and voice concerns, ask questions, and to gain information about upcoming compliance items.	Monthly throughout the year.
Assist Visits - ReliabilityFirst has implemented a program whereby a registered entity may request a one on one or a small group meeting where guidance on compliance related activities can be provided. These Assist Visits can be in the form of a conference call, web meeting, or on-site visit. Topics can range from helping an entity become more familiar with compliance related material and activities, to special guidance and education when either the registered entity or ReliabilityFirst believes the registered entity needs special attention or additional help.	As requested by our registered entities.

Appendix A5 - SERC Reliability Corporation (SERC) 2015 CMEP Implementation Plan

This Appendix contains the CMEP Implementation Plan (IP) for SERC as required by the NERC Rules of Procedure (ROP).

1. Compliance Monitoring and Enforcement

1.1 CMEP IP Highlights and Material Changes

As part of SERC's efforts to be more efficient and effective, and to strengthen and support the Compliance area, the Operations and Planning (O&P) and Critical Infrastructure Protection (CIP) audit resources were brought under one monitoring area function, Compliance Monitoring. This will allow SERC to be more consistent in the application of tools and processes in compliance monitoring activities.

SERC will continue to support its Industry Subject Matter Expert (ISME) program, through which SERC frequently uses industry volunteers employed by registered entities in the SERC Region as supplemental compliance audit team members. SERC continues to be a leader among the Regions in this area. In 2014, the program was enhanced to focus on identification, qualification, and assignment of ISMEs to match the technical resource needs of specific audits, evaluation of ISME participation and performance during audits, and training of ISMEs. During 2015, the ISME program will continue to be supported, highlighted during certain SERC outreach events, and have information available on the SERC public website.

1.2 Other Regional Key Initiatives and Activities

Building from the successful momentum with the Reliability Assurance Initiative (RAI) in 2014, SERC will continue to support RAI in 2015 in various ways. SERC will scope the appropriate Compliance Monitoring Plan for each registered entity based on ERO Risk-based Compliance Oversight Framework, as described in the ERO CMEP IP, which includes: - the NERC 2015 risk elements Guide, SERC Regional Risk Assessment, Inherent Risk Assessment (IRA), and Internal Control Evaluation (ICE). The Compliance Monitoring Oversight Plan will include areas of focus, level of efforts, timing, and overall strategy on use of CMEP tool(s). Note, however, each registered entity remains responsible for compliance with all Mandatory and Enforceable Reliability Standard Requirements applicable to its registered function(s).

For registered entities identified as a Multiple Region registered entity (MRRE), the lead Region shall be responsible for the coordination of compliance monitoring oversight activities. The lead Region is responsible for coordinating and conducting the IRA and ICE; however, each Region shall have input to ensure regional risks are identified. The lead Region may modify the Compliance Monitoring Oversight Plan as appropriate.

2. Regional Reliability Assessment Process and Regional Risk Identification

The SERC Region encompasses a large area, has some of the nation's largest cities and utilities, and serves a significant portion of the U.S. population. Protecting the reliability of the electric grid in the SERC Region is the responsibility of SERC members with the support of SERC staff and reliability programs. Reliable operation of the Bulk Power System (BPS) is essential to regional economic viability. While each registered entity within the SERC Region is diligent with respect to reliability and resiliency within their service area, it is the responsibility of SERC to coordinate the reliability-related activities throughout the Region.

It should be recognized that the BPS in the SERC Region has been planned, built, and operated as part of the integrated Eastern Interconnection. This integrated system serves the electric customers in the region under both traditional vertically integrated and market-based generation dispatch mechanisms.

SERC has worked with its members since 2012 to develop and implement a continuous program of Region-wide assessments of potential reliability risks that could impact the SERC Region BPS. The SERC Regional Reliability Risk Assessment program is a robust, centralized process for analyzing, prioritizing, addressing, and

communicating significant risks and risk-controlled initiatives. This is the first application of the output of this program communicating the choice of Standards for inclusion in the SERC CMEP.

The SERC Standing Committees, the SERC Reliability Risk Team (RRT)[23], and SERC Reliability Assessment and Performance Analysis staff contribute to the SERC Regional Reliability Risk Assessment Program. The objective of the program is to improve BPS reliability through a coordinated effort that identifies, analyzes, prioritizes, and addresses reliability risks. In conformance with the ERO RAI risk management program, the SERC process consists of the following major activities:

- Identify/Nominate Risks
- Determine Time Horizon (e.g. immediate, next-day, operational, seasonal, and long-term).
- Assess and Rank Risk
  - Determination of the consequence, or severity impact(s)
  - Determination of the probability of occurrence
  - Assignment of High, Medium, or Low from the Risk Assessment Matrix
  - Prioritization of risks
  - Stored in the Risk Registry
- Develop Risk Control Initiatives
- Monitor and Reevaluate Risk Impact

The coordination of the efforts with the SERC registered entities, the SERC technical committees, SERC staff, neighboring system personnel, and other members of the ERO is vital to the understanding and analysis of potential major reliability issues. SERC, through its members and staff, is heavily engaged with NERC and its risk initiatives. SERC's risk management programs enable it to focus compliance monitoring oversight activities on those Reliability Standards which, if violated, would pose the greatest risk to the reliable operation of the SERC portion of the BPS. The Reliability Standards listed in Section 3 are the program's recommendation for 2015 and are based on what is known at the time of this submittal.

SERC has recognized one NERC Reliability Standard, PRC-006, as needing greater specificity to achieve successful coordination of the registered entities within the SERC Region. PRC-006 has Requirements that identify the Planning Coordinator (PC) as the registered entity responsible for developing under frequency load shedding (UFLS) schemes within their PC area. However, the NERC Standard does not provide specific guidance regarding the extent of cooperation with surrounding PCs which may lead to inconsistent set points and other regional inconsistencies for key UFLS parameters. In response, SERC created a Regional Reliability Standard, PRC-006-SERC-01, to establish consistent and coordinated Requirements for the design, implementation, and analysis of UFLS programs among applicable SERC registered entities. The Regional Standard adds specificity not contained in the NERC Standard for development and implementation of the UFLS scheme in the SERC Region that effectively mitigates the consequences of an under-frequency event.

SERC has numerous UFLS schemes deployed within its Region; therefore, SERC developed and implemented the Regional Standard to ensure more comprehensive UFLS testing to identify possible regional gaps.

3. Regional Risk Focus Areas and Associated Reliability Standards

The table below contains the Regional risks focus areas identified during the Regional Reliability Assessment process. The table also links associated Reliability Standards/Requirements to identified risks that may be

[23] The RRT includes SERC Engineering Committee, Operating Committee, and CIP Committee members and was explicitly created to formalize and apply a process to carry out the basic elements of reliability risk monitoring, classification and management. It is noteworthy that the RRT monitors many risks not defined in the Reliability Standards, but are in support of best practices that promote BPS reliability.

considered in the Regional Compliance Monitoring Plan. Note that the Standards/Requirements listed below are in addition to the Standards/Requirements identified in the 2015 ERO risk elements Guide.

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
External Risks associated with Critical Cyber Assets	Electronic Access Points (EAP) often provide the first level of defense against vulnerability-based attacks, and based on SERC's most violated Reliability Standards/Requirements (previous three years) CIP-005 is the Region's third most violated CIP Standard. Given the EAP is often the first level of defense, controlling access into the perimeter and monitoring for cyber-based attacks is critical to protecting cyber assets within and reducing the risk of degradation to the BPS.	CIP-005-3a R2, R3
Physical Events/Threats	Physical Events represent those events that result in extensive damage to equipment, irrespective of cause. Based on SERC's most violated Reliability Standards/Requirements report (previous three years) CIP-006 is the Region's second most violated CIP standard. Additional focus is needed to address and minimize both the magnitude and duration of the consequences of a physical event. Physical access to cyber systems must be restricted and appropriately managed to ensure the integrity of the cyber systems within the Physical Security Perimeter.	CIP-006-3c R2, R5, R6
Cyber System Integrity Risks	As the top violated Reliability Standard within the SERC Region, additional focus must be placed on cyber system integrity. Two key parts of ensuring system integrity are security patch and user account management. Security patch management is crucial in monitoring and addressing known security vulnerabilities prior to those vulnerabilities being exploited in a malicious manner that could degrade, or render unavailable, the cyber systems required to ensure the reliability of the BPS. User account management is essential in ensuring only authorized personnel can gain electronic access to Critical Cyber Assets.	CIP-007-3 R3, R5
Cold weather impacts on transmission and generation	The SERC and NERC Polar Vortex related research, final and preliminary reports reveal numerous operational risks inherent to SERC registered entities, which may degrade the SERC Region's BPS reliability performance below what is required by the NERC Standards.	BAL-001-1 R1, R2; BAL-002-1 R1; BAL-005-0.2b R7; COM-002-2 R1, R2

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Major storm events such as hurricanes and tornados	The SERC Region historically has experienced severe weather events, such as hurricanes and tornados. The most recent noteworthy weather events are hurricane Katrina and recurring mass tornado events in 2008 and 2011. These events usually create system contingencies beyond existing planning criteria; however, emergency procedures and other operating standards still apply. Over the years, the Region has identified this risk and emphasized system preparedness through the 2012 Assessment of SERC Performance Information for Identifying Potential Reliability Risk, as well as through the NERC Reliability Assessment reporting process.	COM-002-2 R1, R2
Power System coordination and modeling	Increased BPS use in a manner for which the system wasn't originally designed, coupled with insufficient operating experience, coordinated studies and coordinated operations, can introduce risk to reliable operation of the BPS in the SERC Region. The NERC Arizona-Southern California Outages report highlighted potential areas of vulnerability. Significant changes in generation dispatch, particularly if such changes are unstudied, increases reliability risk. As a result, additional focus on registered entities impacted by these issues with respect to these Standards is warranted. References to neighboring system coordination and recommendations can be found in the NERC Arizona-Southern California Outages report."	MOD-001-1a R6; FAC-008-3 R6; FAC-014-2 R1, R2, R3, R4 ; IRO-003-2 R1, R2; IRO-004-2 R1; VAR-001-4 R1, R2; VAR-002-3 R1, R2, R3
UFLS Schemes	The SERC UFLS Regional Standard is to establish consistent and coordinated requirements for the design, implementation, and analysis of UFLS programs among SERC applicable registered entities. The regional standard adds specificity not contained in the NERC standard for development and implementation of the UFLS scheme in the SERC Region that effectively mitigates the consequences of an under-frequency event.	PRC-006-SERC-01 R1, R2, R3, R4, R5, R6

4. Compliance Oversight Plan

Scheduling of Audits

Registered entities registered as a Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) will continue to be audited every three years per the current NERC ROP. SERC will continue to monitor registered entities that are scheduled for an audit based on SERC's long term monitoring plan in 2015. For all registered entities scheduled for an audit in 2015, flexibility to adjust the periodicity, as well as

audit scope, will be considered and adjusted based upon the Regional Risk Assessment, the Risk-based Compliance Oversight Plan provided by NERC, and the Inherent Risk Assessment (IRA) of the registered entity performed by SERC.

For registered entities registered only as a Purchasing-Selling Entity (PSE), SERC will use the Self-Certification monitoring method in lieu of conducting an audit of these registered entities. This monitoring method was selected based upon SERC's Regional Risk Assessment conducted for 2015 and the limited number of reliability issues posed by PSE operation.

SERC will not conduct an off-site or on-site CIP audit for registered entities that have declared that they own no Critical Assets (CAs) or Critical Cyber Assets (CCAs). This determination is based upon the Cyber Security Reliability Standards CIP V5 Transition Guidance provided by NERC that states, "*For those Responsible Entities that do not have any Critical Assets or Critical Cyber Assets under the CIP V3 Standards, however, Regional Entities will forgo off-site audits of the CIP Reliability Standards during the Transition Period.*" SERC may determine to use another monitoring method based on the registered entity IRA.

SERC is gathering CIP V5 data from its registered entities to better understand the scope and focus of required outreach during 2015 and beyond. SERC is conducting a survey during the implementation period to determine the status of each registered entity's transition to the CIP V5 Standards. Based on the data obtained, SERC will further align its outreach activities.

Self-Certification Monitoring

SERC will use Self-Certifications based on the guidance in the ERO CMEP IP, SERC's annual Regional Risk Assessments, registered entity IRA, internal controls evaluations (if applicable), compliance history, etc. Self-Certifications may also use guided self-certifications that include specific questions and/or data requests. SERC will require all Self-Certifications to be completed on a Requirement basis. This will require a Self-Certification in which all sub-Requirements must be completed for each Requirement listed. SERC will provide additional guidance on Self-Certification requirements to registered entities throughout 2015 as needed

Spot Checking

SERC will determine the need for Spot-Checks based on the outcome of the registered entity IRA. In addition, SERC may use the Spot Check process to verify Mitigation Plans as needed.

Periodic Data Submittals

SERC will still have a number of Standards and Requirements that require a data submittal. Most of these data submittals serve as reminders to our registered entities of a monthly, quarterly, and/or annual reporting Requirement in the Standard.

The audit schedule below shows registered entities that are subject to an audit during 2015 based on the three year cycle prescribed by NERC's ROP. The schedule is also located on the SERC's website here: http://www.serc1.org/Documents/Compliance/2015%20Program/2015%20SERC%20Audit%20Schedule.pdf

2015 Compliance Audit Schedule	
NCR #	**Registered Entity**
NCR01312	South Carolina Public Service Authority-Audit
NCR00070	Southeastern Power Administration-Audit
NCR01225	East Kentucky Power Cooperative-Audit
NCR01223	LG&E and KU Services Company-Audit
NCR01151	Tennessee Valley Authority-Audit
NCR01359	USACE-Mobile District-Audit

2015 Compliance Audit Schedule	
NCR #	**Registered Entity**
NCR01359	City of Springfield, IL-CWLP-Audit
NCR00826	Midwest Independent Transmission System Operator Inc. (RFC Lead)-Audit
NCR01315	South Mississippi Electric Power Association-Audit
NCR01361	USACE-Savannah District-Audit
NCR01234	Entergy-Audit
NCR01320	Southern Company Services, Inc.– Trans-Audit
NCR11305	Smoky Mountain Transmission LLC-Audit

5. Compliance Outreach

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
SERC Compliance Portal SERC registered entities submit Self-Certifications, Self-Reports, Mitigation Plans, and Data Submittals via the SERC Portal. Surveys are conducted for feedback to allow SERC to incorporate enhancements based on the needs of the users and outreach events include training on upgrades and enhancements.	As needed throughout the year
Outreach Events SERC outreach events are planned throughout the year to accommodate the training needs of registered entities. Planned events, listed here, with specific themes will also feature compliance and reliability topics of importance at the time of the event. All events are posted to the SERC website, listed in the SERC Outreach & Training Catalog on the website, featured in the monthly *SERC Transmission* newsletter, and email notifications and reminders are sent to primary and alternate compliance contacts for all registered entities within the SERC Region footprint. • Open Forum (WebEx): SERC's Redesigned Website • Spring Compliance Seminar • Small Entity Workshop: CIP V5 Transition • Open Forum (WebEx) • Open Forum (WebEx) • CIP Compliance Seminar • Fall Compliance Seminar	 Jan 26, 2015 Feb 24-25, 2015 Feb 25, 2015 Apr 13, 2015 Jul 20, 2015 Sep 29-30, 2015 Oct 27-28, 2015
Focused Workshops / Webinars Supplemental focused events will be scheduled on an as-needed basis to provide outreach and training for new or revised Reliability Standards, targeted groups of registered entities based on functional Registration, and ERO initiatives.	As needed throughout the year
Lessons Learned Lessons Learned website postings will share information among registered entities.	As available throughout the year

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Training and Education Catalog SERC maintains a catalog of recorded and upcoming training and education activities on its website to increase the number of people who are aware and are able to take advantage of SERC's training and education programs.	Updated as needed throughout the year
Compliance Outreach Assistance Upon receipt of a New Registration Application, a document containing links to "Compliance 101" files on the FERC, NERC, and SERC websites will be sent to the applicant to provide basic compliance information in one convenient location. A sample of the links includes information such as the Energy Policy Act (EPA) of 2005 on the FERC site, ROP and Reliability Standards on the NERC site, and Acronym Reference Index and SERC Filing Due Dates on the SERC site. The *SERC Transmission* newsletter is distributed to registered entities within the SERC Region on a monthly basis. Articles contain links to scheduled outreach information for both SERC and NERC events, along with other topics helpful to maintain BPS reliability.	Updated as needed throughout the year

Appendix A6 - Southwest Power Pool Regional Entity (SPP RE) 2015 CMEP Implementation Plan

This Appendix contains the CMEP Implementation Plan (IP) for the SPP RE as required by the NERC Rules of Procedure.

1. Compliance Monitoring and Enforcement

1.1 CMEP IP Highlights and Material Changes

SPP RE budgeted for four open positions in 2015 – the Compliance Director, two (2) Lead Engineers and a CIP Compliance Specialist. SPP RE will also utilize contractors or consultants during the 2015 year to assist Staff during audits, investigations and/or enforcement activities.

SPP RE will be developing new tools and templates to implement the Reliability Assurance Initiative (RAI) activities.

1.2 Other Regional Key Initiatives & Activities

SPP RE will continue to collaborate with NERC, Regional Entities and the registered entities to identify changes to enhance the risk-based approach to the monitoring and enforcement processes.
SPP RE CIP Staff will begin an Outreach Program that will assist the registered entities in the transition to CIP version 5.

2. Regional Reliability Assessment Process and Regional Risk Identification

SPP RE has developed a Regional Audit Scope Plan that identifies the risk elements within the SPP RE footprint. The SPP RE risk focus areas identified include the top violated requirements, facility rating impacts, newly enforceable Reliability Standards, System Awareness and protection of Cyber Assets.

SPP RE will consider these Regional risk focus areas when following the ERO Risk-based Compliance Oversight Framework described in the ERO CMEP. SPP RE will also consider the Regional risk focus areas when conducting risk assessments for the registered entities that are scheduled for audits during 2015 to develop the audit scope.

3. Regional Risks Focus Areas and Associated Reliability Standards

The table below contains the Regional risk focus areas identified during the Regional Risk Assessment process. The table also contains associated Reliability Standards/Requirements for identified risks that may be considered in the Regional compliance oversight plan.

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
Protection of Cyber Assets	Essential to ensure the system protecting the cyber system can continue to maintain a security perimeter.	CIP-005-3 R2, R3
Protection of Cyber Assets	Essential to ensure the protection of Cyber Assets from unauthorized physical access.	CIP-006-3 R2, R3, R6
Protection of Cyber Assets	Essential to ensure applicable security patches are identified and installed on the CIP systems.	CIP-007-3 R3, R5
Facility Ratings Impacts	Essential to ensure Generator Owners and Transmission Owners develops, maintain and coordinate accurate facility ratings.	FAC-008-3 R1, R2, R3, R6, R7

Reliability Standards Subject to Regional Monitoring		
Regional Risk Focus Areas	**Justification**	**Associated Standard & Requirement(s)**
Facility Ratings Impacts	Essential to ensure Transmission Operators and Planning Authorities and Reliability Coordinators establish and coordinate SOLs and IROLs.	FAC-014-2 R2
System Awareness	Essential to ensure the Balancing Authorities and Transmission Operators operates and maintains the reliability of the system.	TOP-002-2.1b R6
System Awareness	Essential to ensure the Balancing Authorities and Transmission Operators operates and maintains the reliability of the system.	TOP-004-2 R1, R4
New Requirements	Essential to ensure Generator Owners have a strategy to prevent vegetation encroachment into the MVCD.	FAC-003-3 R3 (GO only)
Top Violated	Top violated in the SPP RE area. Essential to ensure the BPS infrastructure is maintained.	PRC-005-1.b R1, R2

4. Compliance Oversight Plan

SPP RE will use the following monitoring tools for 2015:

On-Site Audits –SPP RE will continue to audit the Transmission Operator and Balancing Authority entities that are on the three (3) year cycle for the Ops & Planning and CIP audits in 2015.

Off-Site Audits- SPP RE will continue to audit the registered entities that are scheduled for a six (6) year audit cycle and for registered entities that have been registered within the last two (2) years for the Ops & Planning, CIP will not perform off-site audits in 2015 per the CIP V3 to V5 Transition Documentation.

Spot-Checks – Spot-Checks may be used in lieu of Off-Site audits for entities that have a lower risk identified through the entity assessment. There are no mandatory Spot Checks listed in the 2015 NERC IP. However, SPP RE may initiate a Spot Check at any time to verify or confirm Self Certifications, Self Reports, and Periodic Data Submittals or in response to operating problems or system events. SPP RE may initiate Spot-Checks for the six (6) year audit cycle registered entities that had Area of Concerns identified in the audits during 2012.

Self-Certification – SPP RE will continue to require SPP RE registered entities to perform a Self-Certification to ensure that the entity is maintaining the rigor of their internal controls for reviewing compliance with the Reliability Standards. SPP RE has identified such requirements based on the ERO CMEP IP and Regional Assessment for the registered entities. Self-Certification will be conducted using webCDMS. Entities will receive additional notice and instructions before each quarterly reporting window. Periodic Data Submittal - The 2015 NERC IP does not identify Reliability Standards and Requirements that require periodic data submittals. SPP RE will require specific Reliability Standards and Requirements that contain periodic data submittal requirements for which SPP RE or SPP RTO will collect on a monthly, quarterly, or annual basis.

The reporting requirements and the Audit Scope Plan are located on the SPP RE's website here: http://www.spp.org/section.asp?group=3290&pageID=27

The audit schedule is also located on the SPP RE's website here:
http://www.spp.org/section.asp?group=3290&pageID=27

2015 Compliance Audit Schedule	
NCR #	**Registered Entity**
NCR01056	American Electric Power Service Corp. (AEPW)
NCR01062	Borger Energy Associates, LP (BOEA)
NCR11291	Chisholm View Wind Project, LLC
NCR11250	Dogwood Power Management, LLC (DPM)
NCR01227	East Texas Electric Cooperative, Inc. (ETEC)
NCR01107	Kansas City Power & Light Company (KCPL)
NCR06047	Lea County Electric Cooperative, Inc. (LCEC)
NCR00826	Midcontinent Independent System Operator, Inc (MISO)
NCR01118	Midwest Energy, Inc. (MIDW)
NCR03044	MISO-MBHydro Contingency Reserve Sharing Group (MRSG)
NCR11236	NAES Corporation - Goodman Energy Center (NAESGEC)
NCR01096	NextEra Energy Resources, LLC (NEXTERA)
NCR06054	North American Energy Services - Dogwood (NAESDOGW)
NCR01124	Northeast Texas Electric Cooperative, Inc (NTEC)
NCR11224	PIC Group, Inc.- Mustang (PICMUS)
NCR11264	Post Rock Wind Power Project, LLC
NCR01148	Sunflower Electric Power Corporation (SECI)
NCR01152	Terrebonne Parish Consolidated Government (TERREBONNE)
NCR01342	Tex-La Electric Cooperative Of Texas, Inc (TEXL)
NCR01160	Western Farmers Electric Cooperative (WFEC) w/ TRE
NCR01081	City Utilities of Springfield
NCR01144	Southwestern Power Administration
NCR01160	Western Farmers Electric Cooperative (WFEC) w/ TRE
NCR00826	Midcontinent Independent System Operator, Inc (MISO)
NCR01101	Grand River Dam Authority
NCR01130	Oklahoma Gas & Electric Company

5. Compliance Outreach

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Newsletters	Monthly
SPP.org RE webpages (http://www.spp.org/section.asp?pageid=87)	Updated as needed
2015 Spring Compliance Workshop	March 10-11, Little Rock
2015 CIP Workshop	June 2-3, Kansas City
2015 Fall Compliance Workshop	September 29-30, Dallas
Webinars	Approx. 9 per year
Training Videos (http://www.spp.org/section.asp?pageID=92)	As developed
Event Analysis Lessons Learned (http://www.spp.org/section.asp?group=2243&pageID=27)	As developed

Appendix A7 - Texas Reliability Entity (Texas RE) 2015 CMEP Implementation Plan

This Appendix contains the CMEP Implementation Plan (IP) for the Texas RE as required by the NERC Rules of Procedure.

1. Compliance Monitoring and Enforcement

1.1 CMEP IP Highlights and Material Changes

Texas RE in 2015 will continue to implement the Reliability Assurance Initiative (RAI), the Electric Reliability Organization's strategic initiative to transform the current compliance and enforcement program into a program that is forward-looking and focuses on high risks to the Bulk Power System (BPS).

In Section 4 below, Texas RE provides a list of registered entities that are planned to undergo compliance monitoring in the Texas Interconnection in 2015 and additional information on its compliance monitoring. Consistent with the NERC Rules of Procedure and approved practices, registered entities were selected for compliance monitoring based on three-year and six-year cycles.

1.2 Other Regional Key Initiatives & Activities

Texas RE will be engaged in a significant amount of outreach associated with transition to CIP Version 5 throughout 2015. The outreach will consist of frequent, information-rich calls, newsletters and specialized workshops (as needed), intended to provide guidance and support for all entities.

Texas RE will continue its collaborative effort between NERC, the Regional Entities, and registered entities to identify and implement changes that enhance the effectiveness of the Compliance Monitoring and Enforcement Program.

2. Regional Reliability Assessment Process and Regional Risk Identification

As part of the Reliability Assurance Initiative, the level of scrutiny a registered entity receives in terms of compliance monitoring will be directly commensurate with the risk it poses to the reliability of the BPS. For entities that do not pose a significant reliability risk, the minimum compliance monitoring activities may suffice. For entities that do pose a significant risk to reliability, it will be necessary for those entities to undergo additional compliance monitoring such as additional focused spot checks, a greater number of Self-Certifications, or broader and deeper audits of greater frequency.

To assist Texas RE in determining how much risk an entity poses to reliability, Texas RE utilizes dedicated staff to review risk within the ERCOT Interconnection. The staff relies heavily on feedback from other groups within Texas RE such as Registration, Enforcement, Reliability Services, and Compliance to achieve an understanding of the risks encountered or emerging within the region. Additionally, Texas RE reviews externally created reports and discussions focusing on reliability risks. The recently developed risk elements Guide provides basic guidance for determining risks for which some level of compliance monitoring may be appropriate. Texas RE will utilize the risk elements Guide to focus on risks within the region by involving local subject matter experts. For example, the Texas RE Reliability Services department creates an annual state of reliability report. Some aspects within the report correlate to the risk elements determined within the risk elements Guide but others are corollaries, such as "Unplanned generation outages with emphasis on winter preparation," a localized issue requiring localized focus. Texas RE will utilize determined risks to facilitate engagements with registered entities in such a way that prioritizes the evaluation of compliance for the determined risks. Texas RE will apply the appropriate risk element or risk elements to the appropriate registered entity to maintain focus on reliability.

Every registered entity is subject to an evaluation of compliance for all Standards determined to be within the Areas of Focus described within the risk elements Guide. Additional risk elements may be added as needed throughout the year. For Critical Infrastructure Protection requirements, Texas RE will utilize the approved transition guide and apply RAI concepts to determine relevant risks to reliability and appropriate Compliance Monitoring and Enforcement Program processes.

3. Regional Risk Focus Areas and Associated Reliability Standards

The table below contains examples of Regional risk focus areas identified during the Regional Reliability Assessment process. The table also contains examples of associated Reliability Standards/Requirements to identified risks that may be considered in the Regional compliance monitoring plan. This table may be updated as needed and in no way restricts Texas RE from utilizing other regional risks and associated Standards/Requirements determined throughout the year.

Reliability Risks Subject to Regional Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Planning	Planning is considered a risk due to the nature of this Interconnection. The list of requirements covers a broad perspective of the different facets of planning requirements that have an impact on reliability.	BAL-001-1 R1-R2; BAL-003-0.1b R1, R2, R4, R5, R6; EOP-001-2.1b R2-R4;EOP-002-3.1 R2; EOP-003-2 R2-R8;EOP-004-2 R1-R3; EOP-005-2 R1, R3, R4, R6; EOP-006-2 R1; FAC-008-3 R3, R6- R8; FAC-010-2.1 R1-R4; FAC-011-2 R1-R4; FAC-013-2 R1; FAC-014-2 R1-R4; PRC-006-1 R1-R14; VAR-001-4 R1-R5; VAR-002-3 R5, R6
Emergency Response and Recovery	The nature of this Interconnection requires monitoring of the reliability related activities needed to respond and recover to emergencies.	BAL-001-1 R1-R2; BAL-002-1 R1; COM-001-1.1 R5; COM-002-2 R1-R2; EOP-001-2.1b R1-R6; EOP-002-3.1 R1-R9; EOP-003-2 R1, R2; EOP-005-2 R1-R18; EOP-006-2 R1-R10 ; EOP-008-1 R1-R8; EOP-010-1 R1-R3; FAC-010-2.1 R2; FAC-011-2 R2; FAC-014-2 R1-R4, R6; IRO-001-1.1 R3, R8; IRO-002-2 R1, R4, R6, R7; IRO-003-2 R1, R2; IRO-005-3.1 R12; IRO-006-5 R1; IRO-006-TRE-1 R1-R2; IRO-009-1 R1-R5; IRO-010-1a R1, R3; IRO-016-1 R1; PER-001-0.2 R1; PER-004-2 R1, R2; PER-005-1 R3; PRC-001-1.1 R2, R6; TOP-001-1a R1-R6, R8; TOP-002-2.1b R6; TOP-003-1 R1; TOP-004-2 R4-R6; TOP-006-2 R5, R6; TOP-007-0 R1-R4; TOP-008-1 R1-R4; TPL-002-0b R1-R3; TPL-003-0b R1-R3; TPL-004-0a R1-R2
SPS Management	SPS remains a facet of operations that can have an impact on reliability. There has been a significant amount of change with respect to the quantity of SPS's within this Interconnect	PRC-001-1.1 R1-R6; PRC-005-2 R1-R5; PRC-015-0 R1-R3; PRC-016-0.1 R1-R3; PRC-017-0 R1-R2

Reliability Risks Subject to Regional Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
UVLS Management	There are areas within this Interconnect that require monitoring of this operational tool.	EOP-003-2 R2, R4, R7; PRC-001-1.1 R1-R5; PRC-004-2.1a R1-R3; PRC-005-2 R1-R5; PRC-010-0 R1; PRC-011-0 R1-R2; PRC-021-1 R1-R2; PRC-022-1 R1
UFLS Management	Frequency control is significant within this Interconnection and monitoring the UFLS aspect is important to ensure reliability.	PRC-001-1.1 R1-R5; PRC-004-2.1a R1-R3; PRC-005-2 R1-R5; PRC-006-1 R1-R12; PRC-008-0 R1-R2;
Local Emergency Management	There are localized emergencies that, if not managed well, could lead to broader impacts to the Interconnection.	COM-001-1.1 R5; COM-002-2 R1-R2, EOP-001-2.1b R1-R5; EOP-002-3.1 R1-R9, EOP-003-2 R1-R8; EOP-005-2 R1-R18; EOP-006-2 R1-R10; IRO-006-TRE-1 R1-R2; TOP-001-1a R1-R6, R8; TOP-002-2.1b R1, R4, R6, R10; TOP-003-1 R1-R3; TOP-004-2 R1-R4, R6; TOP-006-2 R1, R2, R4; TOP-007-0 R1-R4; TOP-008-1 R1-R4
Operations Guides (RAP, MP, PCAP, TOAP, etc…)	The management of the various operating tools available to preserve reliability require a level of compliance monitoring.	IRO-006-TRE-1 R1-R2
SOL/IROL Coordination	The nature of the Interconnection requires this risk to be closely monitored and reviewed.	COM-002-2 R1-R2; EOP-001-2.1b R1-R3; FAC-002-1 R1; FAC-008-3 R1-R3, R6, R8; FAC-010-2.1 R1-R4; FAC-011-2 R1-R4; FAC-013-2 R1, R2, R4, R5; FAC-014-2 R1-R5 ; IRO-001-1.1 R1, R2, R4, R6-R9; IRO-002-2 R3-R5, R7; IRO-003-2 R1-R2; IRO-004-2 R1; IRO-005-3.1a R1, R2, R5, R9, R12; IRO-006-5 R1; IRO-006-TRE-1 R1-R2; IRO-008-1 R1-R2; IRO-009-1 R1-R5; IRO-010-1a R1-R2; IRO-014-1 R1-R4; IRO-015-1 R1; MOD-010-0 R1; MOD-012-0 R1-R2; MOD-018-0 R1; NUC-001-2.1 R4, R9; PER-004-2 R2; PER-005-1 R3; TOP-001-1a R1-R3, R7; TOP-002-2.1b R1, R2, R4, R10, R11, R13, R16, R18; TOP-003-1 R1, R2; TOP-004-2 R1, R4-R6; TOP-005-2a R2; TOP-006-2 R3, R5, R6; TOP-007-0 R1, R2, R4; TOP-008-1 R1-R4; TPL-001-0.1 R1-R2; TPL-002-0b R1-R2; TPL-003-0b R1-R2; TPL-004-0a R1; VAR-002-3 R2
Critical Voltage Support	This risk is closely related to the UVLS management but covers risks in other portions of the Interconnect that may not have UVLS.	CIP-002-3 R1; COM-002-2 R1; FAC-002-1 R1; FAC-008-3 R6, R7, R8; IRO-002-2 R4, R5; PRC-010-0 R1; PRC-011-0 R1-R2; TOP-003-1 R2; TOP-006-2 R2, R5; VAR-001-4 R1-R5; VAR-002-3 R1-R4, R6

Reliability Risks Subject to Regional Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
SCADA/EMS Outage and Problems	NERC has recognized this as a re-occurring event that requires monitoring to determine impacts to reliability.	CIP-003-3 R1,R2, R4-R6;; CIP-005-3a R1-R4; CIP-006-3c R2-R6; CIP-007-3a R1-R9; CIP-008-3 R1-R2; CIP-009-3 R1-R4; COM-001-1.1 R1-R5; COM-002-2 R1-R2; EOP-001-2.1b R2, R3, R5; EOP-003-2 R5, R6, R8; EOP-004-2 R1-R2; EOP-005-2 R1, R3, R10; EOP-008-1 R1-R8; IRO-001-1.1 R1, R4; IRO-002-2 R5, R6, R7, R8; IRO-003-2 R1, R2; IRO-005-3.1a R1, R2, R5, R7, R8, R9; IRO-006-TRE-1 R1, R2; IRO-010-1a R1; PER-005-1 R1; PRC-001-1.1 R6; TOP-001-1a R1-R5, R7-R8; TOP-002-2.1b R1, R5, R6, R10, R11, R14, R16; TOP-004-2 R1, R4, R6; TOP-005-2a R2; TOP-006-2 R1-R6; TOP-007-0 R1; TOP-008-1 R1-R4
Internal Access Points PSP	Even with the transition to CIP V5 there is a need to maintain security and provide monitoring activities associated with CIP.	BAL-005-0.2b R3; CIP-002-3 R1-R2; CIP-003-3 R1, R5; CIP-004-3a R1-R4; CIP-006-3c R1-R6, R8
External Access Points ESP	Even with the transition to CIP V5 there is a need to maintain security and provide monitoring activities associated with CIP.	BAL-005-0.2b R3; CIP-002-3 R1-R3; CIP-003-3 R1, R4-R6; CIP-004-3a R1-R4; CIP-005-3a R1-R4
Network Architecture	Even with the transition to CIP V5 there is a need to maintain security and provide monitoring activities associated with CIP.	BAL-005-0.2b R3; CIP-002-3 R1-R3; CIP-003-3 R1,R2, R4-R6; CIP-004-3a R1-R4; CIP-005-3a R1-R4; CIP-006-3c R2-R6; CIP-007-3a R1-R9
Critical Assets Selection	Even with the transition to CIP V5 there is a need to maintain security and provide monitoring activities associated with CIP.	BAL-005-0.2b R3; CIP-002-3 R1-R4
Frequency Response and Control	The nature of this Interconnection requires monitoring of the reliability related activities needed to maintain frequency.	BAL-001-1 R1-R3; BAL-001-TRE-1 R2, R3, R6-R10; BAL-003-0.1b R1, R4; BAL-005-0.2b R14; COM-002-2 R1; EOP-001-2.1b R2; EOP-002-3.1 R5; EOP-003-2 R6, R7; EOP-006-2 R7; PRC-006-1 R1-R14; PRC-008-0 R1, R2; TOP-006-2 R7
Protection System Performance	Protection System performance remains a risk requiring focused attention.	PRC-001-1.1 R2-R6; PRC-004-2.1a R1-R3; PRC-023-3 R1-R6,; PRC-025-1 R1;

Reliability Risks Subject to Regional Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Operational Communication	Communication is a critical aspect of reliability.	BAL-003-0.1b R1; BAL-004-0 R2, R4; BAL-005-0.2b R4; BAL-006-2 R2-R5; COM-001-1.1 R1, , R3, R4; COM-002-2 R1, R2; EOP-001-2.1b R3, R6; EOP-002-3.1 R3, R7, R9; EOP-003-2 R3; EOP-005-2 R1-4, R8, R15; EOP-006-2 R2, R4, R5, R7, R8, R10; EOP-008-1 R8; EOP-010-1 R2; FAC-001-1 R1;; IRO-002-2 R1-R3; IRO-004-2 R1; IRO-005-3.1a R3, R4, R6, R9, R10, R12; IRO-006-5 R1; IRO-009-1 R4; IRO-016-1 R1; PRC-001-1.1 R2, R6; TOP-001-1a R3-R5, R7, R8; TOP-002-2.1b R3, R4, R11, R13-R17,; TOP-003-1 R1-R3,; TOP-004-2 R6,; TOP-005-2a R1-R3; TOP-006-2 R1; TOP-007-0 R1, R4; TOP-008-1 R3; VAR-001-4 R3; VAR-002-3 R1-R4, R6
Renewables Integration	The management of renewable integration is important to reliability due to the nature of this Interconnection. The Interconnect has had a significant change in topology to allow integration and the results of that integration are becoming more apparent during grid operations.	BAL-001-TRE-1 R2, R3, R6-R10; BAL-005-0.2b R1, R14; CIP-002-3 R1-R3,; COM-002-2 R1-R2; EOP-004-2 R1, R2; FAC-001-1 R1-R3; FAC-002-1 R1; FAC-008-3 R1, R2, R6, R7; IRO-002-2 R1-R8; MOD-026-1 R2-R5; MOD-027-1 R1-R5; PRC-001-1.1 R3; PRC-018-1 R1-R6; TOP-001-1a R3, R6, R7; TOP-002-2.1b R13- R15; TOP-006-2 R1; VAR-002-3 R1-R2

4. Compliance Oversight Plan

Texas RE will use the approved ERO Compliance Oversight Framework, as described in the ERO CMEP IP, to determine the scope of each compliance engagement and the method for conducting the engagement (such as by audit, Self-Certification, or spot check). Texas RE will evaluate risk elements and apply compliance monitoring subject to NERC Standards and Requirements applicable to the risks. Each registered entity will undergo an Inherent Risk Assessment using characteristics of the specific entity to help determine the scope of the compliance review. The scope of review may be further tailored for those registered entities that opt to undergo an Internal Control Evaluation.

Texas RE will notify registered entities of upcoming compliance engagements within the timeframes required by Appendix 4C to the NERC Rules Procedure (at least 90 days before an audit, 30 days before a Self-Certification, and 20 days before a spot check).

Texas RE will evaluate Operations and Planning Requirements and Critical Infrastructure Protection Standards and Requirements concurrently during an engagement instead of conducting separate engagements. For Critical Infrastructure Protection Requirements, Texas RE will refer to the approved transition guide.

Texas RE will also implement a change for use of Self-Certifications for registered entities within the Texas RE footprint. Texas RE will require more information from entities selected to self-certify, and the Self-Certification will be limited to Standards and Requirements related to risks identified through the compliance monitoring processes. The intent of this change is to implement RAI goals by focusing on risks and properly leveraging the resources of registered entities and Texas RE.

Texas RE will use the approved Compliance Oversight Framework to determine the scope of each compliance engagement and the method for conducting the engagement (such as by audit, Self-Certification, or spot check). Texas RE will notify registered entities of upcoming compliance engagements within the timeframes required by Appendix 4C to the NERC Rules Procedure (at least 90 days before an audit, 30 days before a Self-Certification, and 20 days before a spot check). The candidate list below is considered an initial list and is subject to change.

2015 Compliance Audit Schedule	
NCR #	**Registered Entity**
NCR01160	Western Farmers Electric Cooperative
NCR01342	Tex-La Electric Cooperative of Texas, Inc.
NCR02910	Nextera Energy Resources, LLC
NCR04003	Forest Creek Wind Farm, LLC
NCR04004	Sand Bluff Wind Farm LLC
NCR04006	American Electric Power Service Corp.
NCR04010	Barney M Davis Unit 1
NCR04013	Bluebonnet Electric Co Op, Inc.
NCR04018	Brownsville Public Utilities Board
NCR04021	Brownsville Public Utilities Board Silas Ray
NCR04027	Calpine Power Management, LP
NCR04038	CPS Energy
NCR04056	ERCOT ISO
NCR04082	Ingleside Cogeneration, LP
NCR04092	Lower Colorado River Authority
NCR04094	Magic Valley Electric Coop Inc.
NCR04118	San Bernard Electric Coop, Inc.
NCR04119	Sharyland Utilities LP
NCR04121	Sid Richardson Carbon LTD
NCR04124	South Texas Electric Cooperative, Inc.
NCR04127	STP Nuclear Operating Company
NCR04160	Weatherford Municipal Utility System
NCR10004	City of Georgetown
NCR10090	NRG Texas Power, LLC
NCR10173	Champion Wind Farm, LLC
NCR10174	Roscoe Wind Farm, LLC
NCR10211	Electric Transmission Texas, LLC
NCR10219	Luminant Generation Company, LLC
NCR10249	Panther Creek Wind Farm I & II, LLC
NCR11074	Wind Energy Transmission Texas, LLC
NCR11076	Lone Star Transmission, LLC
NCR11383	EC&R QSE, LLC

5. Compliance Outreach

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Spring Compliance Workshop	Spring 2015
Fall Compliance Workshop	Fall 2015

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Talk With Texas RE	Projected Monthly (subject to change)
Texas *Re*view Newsletter	Projected Monthly
CIP Compliance Workshop(s)	**Summer 2015**

Appendix A8 - Western Electricity Coordinating Council (WECC) 2015 CMEP Implementation Plan

This Appendix contains the CMEP Implementation Plan (IP) for WECC as required by the NERC Rules of Procedure.

1. Compliance Monitoring and Enforcement

1.1 CMEP IP Highlights and Material Changes

Enhanced Regional Coordination

In 2014, WECC coordinated enforcement activities for some registered entities across multiple regions. In addition, WECC continued to identify registered entities that could qualify for coordinated compliance and enforcement activities under a forthcoming Multi-Regional registered entity (MRRE) Process. WECC plans to work with NERC and the other Regions in 2015 to implement the MRRE Process as appropriate.

Departmental Reorganization: Enforcement and Compliance Risk Analysis

In 2014, the WECC Compliance Department restructured to more appropriately allocate resources to prepare to implement the Reliability Assurance Initiative (RAI) in 2015. Subject matter experts previously working within the WECC Enforcement Team moved to the newly created Compliance Risk Analysis functional group. The Compliance Risk Analysis Group will continue to focus on conducting reviews and technical assessments of all self-identified violations and mitigation plans. In addition, this group will focus on Inherent Risk Assessments (IRAs) and Internal Controls Evaluations (ICEs) as part of the RAI.

Strengthened Settlement Process

During 2014, WECC continued to leverage information gained from risk analysis, lessons learned, best practices, and other information to enhance monitoring and enforcement activities. For example, in negotiating settlement agreements disposing of violations, WECC may propose reliability-focused terms aimed at improving reliability, culture of compliance, internal controls, and internal compliance programs. Most settlements reached in 2014 included such reliability-focused activities. In addition, WECC began sharing best practices and lessons learned on its Compliance website during 2014 and will continue to expand this information in 2015.

1.2 Other Regional Key Initiatives & Activities

During 2015, WECC will implement the ERO's risk-based approach to compliance monitoring in conducting CMEP-related activities. WECC will phase in implementation of IRA and ICE activities to help determine the best use of its resources and understand that WECC's processes will evolve throughout the year.

Risk-based Framework for Off-site Audits

In 2015, WECC will implement the ERO Risk-based Compliance Oversight Framework, as described in the ERO CMEP IP, for conducting off-site audits for certain registered entities, different from the annual "one-size-fits-all" formal off-site compliance audit strategy that WECC has implemented since 2007. This tailored audit strategy considers the inherent risks posed by the registered entities in choosing the appropriate monitoring engagement.

WECC conducted a risk assessment of all entities scheduled for off-site audits in 2015. Based on the risk assessment, WECC will conduct off-site audits as usual for some entities. However, for most entities otherwise due for the off-site audit, WECC will substitute the annual Self-Certification process, combined with a focused validation of the annual Self-Certifications. WECC plans to continue to perform all on-site audits during 2015 as scheduled.

Inherent Risk Assessment (IRA) Process

WECC Compliance will perform an IRA of registered entities to identify areas of focus and the level of effort needed to monitor compliance with NERC Reliability Standards for a particular Entity or category of Entity. While the IRA is similar in nature to what WECC has been doing in the past several years when scoping audits, the IRA will strengthen the process. In 2015, WECC plans to conduct IRAs for registered entities that have an on-site audit scheduled. If resources permit, during 2015 WECC may conduct IRAs for other registered entities as well.

Internal Controls Evaluation (ICE) Process

WECC Compliance may perform an ICE of certain registered entities to assess their internal controls, which may further focus the level and effort needed to monitor compliance with NERC Reliability Standards for a particular Entity. For 2015, WECC will roll out the ICE process on a limited basis. Any entity that has a scheduled audit in third or fourth quarters 2015 may volunteer for the ICE program. WECC will contact each such entity in early 2015 to provide more information and discuss the Entity's options. If a registered entity volunteers for the ICE process, WECC will evaluate its internal controls that support compliance with the Reliability Standards. WECC will assess the strength of these controls and provides the entity with feedback. WECC will use its evaluation of internal controls to determine the scope and depth of the compliance monitoring activity and any potential impacts on enforcement processing of violations and mitigation plans submitted by entities. Registered entities may elect not to participate in an ICE. In that case, WECC will use the results of the IRA to determine the appropriate compliance monitoring strategy. WECC also will provide more information in 2015 regarding the expansion of this program in 2016 and beyond. For Entities not eligible for this process in 2015, WECC will work with interested entities to recommend how it could focus on identifying, organizing, and strengthening detective, preventative and corrective controls pertaining to the Reliability Standards. WECC will post guidance specific to its ICE review process in early 2015 and will update ICE-related information during the year as appropriate.

Internal Compliance Program Assessment (ICPA)

WECC will continue its voluntary ICPA Program, originally launched during 2012, in 2015. The ICPA Program is a tool Entities can but are not required to use to assist in the development of strong Internal Compliance Programs (ICPs). WECC provides feedback, highlighting exemplary practices and providing recommendations for improvement where appropriate. As the ICE process develops, WECC will consider merging the ICPA process with the ICE process.

CIP v5 Implementation

In 2014, WECC made significant efforts to prepare both staff and registered entities to be compliant with CIP v5. WECC will follow NERC's Transition Guidance for CIP-related monitoring and enforcement during 2015, in anticipation of the 2016 compliance date. During 2014, WECC conducted numerous outreach activities and materials to assist registered entities in making the transition. All presentations and associated material are available via WECC's website.

The WECC Cyber Security Audit Team will use the NERC CIP v5 transition guidance in conjunction with the NERC RAI program during its 2015 audit engagements. While maintaining its schedule of 2015 on-site audits, the WECC Cyber Security Audit Team will continue to engage its registered entities, NERC and the other Regions in ensuring a consistently applied audit approach on CIP v5.

WECC encourages registered entities to take a proactive approach in transitioning to CIP v5. If registered entities encounter any issues in its transition, WECC encourages them to contact WECC to work through the issues.

Physical Security Standard Implementation

WECC has been actively engaged in CIP-014 activities during 2014, dedicating resources and leveraging key relationships with Standard Drafting Team members and industry to inject subject matter expertise and practical experience into both the Standard and RSAW. WECC has a number of CIP auditors with strong physical security credentials. To share this expertise, WECC has developed and delivered multiple presentations to both industry and other Regions, providing a "next-steps" perspective aimed at aiding registered entities in a move toward increased security and compliance with CIP-014. Presentations and other materials are on WECC's website.

2. Regional Risk Assessment Process

This section provides a description of how WECC assessed risk in the Western Interconnection and determined associated Reliability Standards for consideration its Regional compliance monitoring plan. In identifying risks, WECC considered risks identified by NERC in its risk elements Guide for Development of the 2015 CMEP IP. In addition, for the Western Interconnection, WECC specifically considered factors such as footprint and registered entity characteristics, registered functions, geographic locations, system events and trends, compliance history, SCADA systems, FERC Orders and Guidance, et al. A summary of the specific risks, and associated standards, follows, for both Critical Infrastructure Protection (CIP) and Operations and Planning (O&P) Standards:

3. Regional Risks and Associated Reliability Standards

The standards identified below generally will be in scope for compliance monitoring for entities to which the standards apply, and thus they are similar to the Actively Monitored Lists in the past. During 2015, as WECC phases in and matures its RAI-related activities, it will begin to tailor monitoring activities to more closely match individual entity risks. WECC may contact individual Entities to provide more focused scope for audits or Self-Certifications, for example. WECC will give priority to focusing on entities scheduled for on-site audits during 2015, and to other Entities for which it may have conducted the Inherent Risk Analysis and, if applicable, the Internal Controls Evaluation.

Critical Infrastructure Protection (CIP)

Over the past several years, cyber security threats have been on the rise in the electricity sector. As Entities have become more reliant on automated systems and integrated technology, it has become more important to identify the cyber security risks associated with using these advanced technologies. While the electric sector has yet to experience a cyber-attack affecting reliable operation of the Bulk Power System, WECC believes the risk of a large-scale cyber-attack is significant and must be addressed to the extent possible through standards monitoring. To help focus compliance monitoring and enforcement efforts, WECC has identified seven cyber security areas of risk that pose the greatest threat to the Western Interconnection.

WECC's Compliance Risk Analysis and Cyber Security Audit teams developed the seven areas of risk identified below. These risks were identified by considering the risks identified by NERC, the history of most violated CIP Standards in the Western Interconnection, and WECC's experience in conducting Cyber Security audits, reviewing self-disclosed violations, and professional expertise of Compliance Risk Analysis and Cyber Security Audit teams.

- **Event and incident response, continuity of operations**: This area relates to establishing and maintaining plans, procedures, and technologies to detect, analyze, and respond to cyber security events.
- **Threat and vulnerability management**: This area relates to establishing and maintaining plans, procedures, and technologies to detect, identify, analyze, manage, and respond to cyber security threats and vulnerabilities.
- **Risk management**: This area relates to establishing, operating, and maintaining an enterprise cyber security risk management program to identify, analyze, and mitigate cyber security risk to the organization.

- **Asset and configuration management**: This area relates to managing an entity's information technology assets, including hardware and software.
- **Identity and access management**: This area relates to creating and managing logical or physical access to an entity's assets.
- **Workforce management**: This area relates to establishing and maintaining plans, procedures, technologies, and controls to create a culture of cyber security and to ensure the ongoing suitability and competence of personnel.
- **Situational awareness**: This area relates to establishing and maintaining activities and technologies to collect, analyze, alarm, present, and use power system and cyber security information, including status and summary information.

As part of this project, WECC also identified the CIP Standards most commonly associated with these areas of risk. Based on the degree of association of the CIP Standards with a given risk area, WECC created a list of Standards most closely associated with these areas of risk:

CIP Reliability Standards Subject to WECC Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Event and incident response, continuity of operations	It is essential for registered entities to develop plans to respond to cyber-security events. Failure to do so could significantly increase the exposure of the threat and time a realized threat exists. Significant impact could occur if entities cannot properly and quickly respond to threats. This area has been reported on as needing attention in the NERC Cyber Attack Task Force final report and the ERO Priorities – RISC Updates and Recommendations report.	CIP-007 R6 CIP-008 R1 CIP-009 R2
Threat and vulnerability management	Not having procedures to detect and respond to cyber vulnerabilities could adversely affect organizational operations, including logical and physical assets. This risk area has been highlighted in the NERC Cyber Attack Task Force final report, ERO Priorities – RISC Updates and Recommendations report, 2013 Long-Term Reliability Assessment report, and ERO Top Priority Reliability Risks 2014-2017 report.	CIP-005 R4 CIP-007 R8 CIP-008 R1
Risk management	A risk management program that oversees an organization's cyber security risk could have far reaching affects throughout all the entity's cyber security programs to mitigate threats both physical and logical. This area makes the foundation of a registered entity's cyber security framework. The DOE guide "Risk Management Process" highlights the need for cyber security risk management being a part of an organization's mission and business requirement.	CIP-002 R1 CIP-008 R1

CIP Reliability Standards Subject to WECC Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Asset and configuration management	Not knowing which assets are performing critical functions for the entity could lead to misconfigured assets and lack of necessary protections for those assets. Since asset configurations impact the security and operation of every asset, it is critical to properly account for, and manage this area.	CIP-002 R2 CIP-002 R3 CIP-003 R6 CIP-005 R1 CIP-007 R1 CIP-007 R2 CIP-007 R3 CIP-007 R4
Identity and access management	Identity and access management is one of the most important components of a registered entity's security infrastructure. An entity's information assets must be accessible only to individuals who are granted explicit entitlements to specific information. Failure to manage identity and access to cyber assets could allow malicious individuals to have access to key facilities, devices and services.	CIP-004 R4 CIP-005 R2 CIP-006 R1 CIP-006 R4 CIP-007 R5
Situational awareness	Not having information about an entity's systems does not allow the entity to take corrective actions to detect and prevent failure and compromise. It is essential for registered entities to have awareness about their environment. Failing to do so could them from being protected against attacks. The RISC's ERO Priorities – RISC Updates and Recommendations report, NERC's ERO Top Priority Reliability Risks 2014-2017 report, and the Cyber Attack Task Force final report highlight this concern.	CIP-005 R3 CIP-006 R5 CIP-007 R6

Operations and Planning (O&P)

The O&P Audit team and Compliance Risk Analysis team have identified areas of risk to the Western Interconnection. These risks were identified by considering the risks identified by NERC documents (*ERO Top Priority Reliability Risks 2014-2017* and *2015 ERO Compliance Monitoring and Enforcement Implementation Plan*), history of most violated Operations and Planning Standards in the Western Interconnection, Event analysis reports, WECC's experience in conducting Operations and Planning audits, reviewing self-disclosed violations, and professional expertise of WECC Compliance Risk Analysis and Operations and Planning Audit teams.

- **Human Performance**: This area relates to a range of issues facing the electricity industry today, including the imminent loss of critical skills and knowledge with the retirement of an aging workforce, cognitive overload of System Operators complicating the task of maintaining reliability, and an apparent shift in operating philosophy toward operating to standards rather than to reliability.
- **Equipment Failure**: This area relates to equipment failure due to aging infrastructure of generation facilities, transmission facilities, and substations. In addition to this, there is a risk associated with failure of adequate coordination with other entities and consideration of impact on the BPS.
- **Changing Resources: Variable Generation Integration**: This area refers to the composition of installed electric generation capacity that makes up the resource portfolio. Additionally this area also refers to the challenges faced due to integration of variable generation, planning for changes in system composition, replacing retired capacity or coal generation.

- **Protection System Reliability:** This area relates to Special Protection Scheme/Remedial Action Scheme (SPS/RAS) effectiveness, SPS/RAS proliferation, misoperation of the protection system devices, and increasing RAS events. In addition to this, there is a risk associated with failure of adequate coordination with other entities and consideration of impact on the BPS.
- **Situational Awareness**: Situational awareness refers to the ability to see and comprehend what is happening on the system. This area relates to importance of including Real-Time Contingency Analysis (RTCA) Tools, next-day studies in planning studies. It also relates to inadequate data coordination, data failure, data shrinkage (unexpected outages of tools providing data to operators) leading to operators not having enough visibility to some or all the system they operate.
- **Changing Load Composition**: This area relates to changing load shape, changing load patterns, increased A/C penetration like plug-in vehicles.
- **Vegetation and Right of Way issues**: This area relates to outages that are caused due to inability to maintain vegetation like grow-in issues in the transmission line or Right of Way clearance issues. It refers to recently approved new NERC standard that specifically relates to the outages caused due to interrelationship between vegetation growth rates, vegetation control methods and inspection frequency which if ignored might lead to encroachment into minimum vegetation clearance distances. This can lead to loss of load or generation.
- **Transmission Planning Adequacy:** This area relates to need and importance of transmission study models in forecasting and monitoring load, transmission, generation, and facility devices.
- **High-Impact Low-Frequency Events:** This area relates to specific events that might not happen frequently but might pose a higher impact to the reliability of the BPS.
- **Adequacy of Reserves:** This area relates to changing Reserve Sharing requirements due to increasing risk of distributed generation, retirement of certain generations due to environmental regulations.

As a result of this project, WECC identified the O&P Standards most commonly associated with these areas of risk. Based on the degree of association of the O&P Standards with a given risk area, WECC created a list of Standards most closely associated with these areas of risk:

O&P Reliability Standards Subject to WECC Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Human Performance	Human Error has been responsible for many historical outages. Human performance challenges encompass a range of issues including the imminent loss of critical skills and knowledge with the retirement of an aging workforce, cognitive overload of System Operators complicating the task of maintaining reliability, and an apparent shift in operating philosophy toward operating to standards rather than to reliability. These issues are pervasive and require coordinated industry efforts to address.	COM-002-2 R2 PER-005-1 R3

O&P Reliability Standards Subject to WECC Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Equipment Failure	As the components of the BPS continue to age, the likelihood of failure increases. Additionally, engineering margins have been minimized through advances in technology which means that BPS components construction practices are less robust. For example, a 1940's transformer may have been over-built to take system changes, but today's transformers are built with thinner margins and are less likely to withstand system dynamics as well. Hence, tracking the rate of occurrence aids industry in understanding and identifying potential systemic issues, such as manufacturing flaws or operational practices. The 2013 and 2014 NERC State of Reliability Reports identified AC substation equipment failure as significant contributors to disturbance events, with a positive correlation to increased transmission outage severity.	FAC-501-WECC-1 R3 PRC-005-1 R2 PRC-005-2 R3 PRC-005-2 R4 PRC-008-0 R1 PRC-008-0 R2 PRC-011-0 R1 PRC-017-0 R1
Changing Resources: Variable Generation Integration	With the increased installation of variable generation, fluctuations in generation and load increase the dependency of system reserves, peaking plants, and energy storage systems. Also, as generation and load fluctuate, facilities need to ramp up and down more frequently increasing maintenance requirements and the risk of mechanical and electrical failures. As more renewable resources are brought online and traditional resources are decommissioned, the available rotating inertia and base-load is reduced which may increase the risk to BES stability. Maintaining resource adequacy will be an ongoing challenge as the resource mix changes. As noted in the WECC annual Power Supply Assessment Report's current projection, the reserve margins will be adequate for the next seven to ten years. Changes outside the assumptions used in resource adequacy evaluations could present challenges. Coal plants are also used for base loading. With the expansion in variable generation, base load plants are needed to provide operating reserves during periods of generation fluctuations (solar and wind). The loss of these plants will increase generation availability risk and grid volatility.	BAL-002-WECC-2 R1 BAL-002-WECC-2 R2 BAL-002-WECC-2 R3 BAL-002-WECC-2 R4

O&P Reliability Standards Subject to WECC Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Protection System Reliability	A failure of the protection system reliability could result in increased risk of cascading events, system instability, and interconnection separations. While protection systems continue to be upgraded to microprocessor based systems, the older Electro-Mechanical and solid state designs are still used and, given their age, impose a risk to reliability. Additionally, interaction of Remedial Action Scheme (RAS) poses a challenge. RAS are designed and tested for specific systems or parts of systems, so their operation in protecting those systems is well understood. But understanding of how RAS interact or impact one another is less well understood. Evaluating the potential interactions, and then managing those interactions that present a risk, is important for reliability.	PRC-001-1.1 R3 PRC-001-1.1 R4 PRC-001-1.1 R5 PRC-001-1.1 R6 PRC-004-2.1a R1 PRC-004-2.1a R2 PRC-004-WECC-1 R1 PRC-004-WECC-1 R2 PRC-005-1 R2 PRC-005-2 R3 PRC-005-2 R4 PRC-008-0 R1 PRC-008-0 R2 PRC-011-0 R1 PRC-016-0.1 R1 PRC-016-0.1 R2 PRC-017-0 R1 PRC-023-3 R1 PRC-025-1 R1
Situational Awareness	Situational Awareness refers to the ability to see and comprehend what is happening on the system. There are a number of processes necessary to maintaining situational awareness, including real-time monitoring and real-time and near-term contingency analysis studies. The coordination and sharing of data is critical to situational awareness because each process relies on various types of data. The lack of adequate situational awareness limits entities' ability to identify and plan for the next most critical contingency, which, in turn, impacts the reliability of the entire system.	COM-002-2 R1 EOP-010-1 R2 EOP-006-2 R1 EOP-006-2 R9 EOP-006-2 R10 EOP-008-1 R3 EOP-008-1 R4 IRO-002-2 R6 IRO-002-2 R7 IRO-002-2 R8 IRO-005-3.1a R1 IRO-008-1 R1 IRO-008-1 R2 PER-005-1 R3 TOP-002-2.1b R4 TOP-002-2.1b R11 TOP-002-2.1b R19 TOP-004-2 R6 TOP-006-2 R2 TOP-007-WECC-1a R1

O&P Reliability Standards Subject to WECC Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Changing Load Composition	Load composition refers to the combination of energy consumption patterns, e.g., peaks, and types of demand, e.g., residential or commercial. Both consumption patterns and types of demand are changing. Future changes to load composition could present operational and planning challenges like mechanism for reducing demand, mechanism for removing load, high penetration of new types of demand and load changes that affect stability considerations.	BAL-002-WECC-2 R1 BAL-002-WECC-2 R2 BAL-002-WECC-2 R3 BAL-002-WECC-2 R4 PER-005-1 R3 TPL-001-0.1 R1 TPL-002-0b R1 TPL-003-0b R1 TPL-004-0a R1
Vegetation and Right of Way issues	Vegetation management and Right of Way issues refer to the encroachment of vegetation due to lack of trimming or due to incorrect clearances of the transmission lines. Aging transmission lines might not adhere to the minimum clearances. Having less clearance along with vegetation growth issues could lead to vegetation related outages. Per NERC Technical Reference, trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.	FAC-003-3 R1 FAC-003-3 R2 FAC-003-3 R6 FAC-003-3 R7
Transmission Planning Adequacy	Maintaining a healthy transmission system is vital for reliability of the grid. Transmission Planning adequacy refers to accuracy and reliability of various study models to study load forecast, transmission system behavior for addition or retirement of generating facilities and facility designs. A coordinated and accurate transmission model becomes important for identifying system behaviors and planning for future load demand. Additionally, planning and operational models that use different representations lead to inconsistent understanding of contingencies and duplication of modeling efforts, both of which may lead to inaccurate prediction of power system behavior.	FAC-014-2 R5 FAC-014-2 R6 TOP-004-2 R6 TOP-006-2 R2 TOP-008-1 R4 TPL-001-0.1 R1 TPL-002-0b R1 TPL-003-0b R1 TPL-004-0a R1
High-Impact Low-Frequency Events	High-impact low-frequency events refer to events such as coordinated physical or cyber-attack, pandemic, geomagnetic disturbance, or large-scale disasters. A coordinated attack on the electric system could result in damage to key systems and components and render part or all of the system inoperable for an extended period of time.	EOP-001-2.1b R2 EOP-001-2.1b R3 EOP-001-2.1b R4 EOP-003-2 R8 EOP-005-2 R1 EOP-005-2 R6 EOP-005-2 R9 EOP-005-2 R10 EOP-005-2 R11 EOP-005-2 R17 EOP-006-2 R1 EOP-006-2 R9 EOP-006-2 R10 EOP-008-1 R3

O&P Reliability Standards Subject to WECC Monitoring		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
		EOP-008-1 R4 PER-005-1 R3
Adequacy of Reserves	Plant retirements due to implemented environmental regulations increase uncertainty in future resources. Additionally, other potential environmental regulations are leading to cases where resources may be inadequate to ensure firm demand is served at all times. As the system continues to change, some concerns are identified with insufficient reserve margins by some entities.	BAL-002-WECC-2 R1 BAL-002-WECC-2 R2 BAL-002-WECC-2 R3 BAL-002-WECC-2 R4

4. Compliance Oversight Plan

WECC will perform all on-site audits during 2015 as scheduled, as required by the NERC Rules of Procedure. Entities scheduled for on-site audits during 2015 are included in the table titled "2015 Audit Schedule" below. For all such audits, WECC will apply a risk-based approach in accordance with the RAI.

For Entities due for an off-site audit during 2015, WECC has conducted a risk assessment. Based on that assessment, WECC has, for most of these entities, substituted the annual Self-Certification process for reporting year 2014 combined with a focused validation of the Self-Certifications. WECC will conduct off-site audits as scheduled for all other Entities. Entities still scheduled for an off-site audit are included in the 2015 Audit Schedule below

Compliance Audits

WECC will conduct scheduled Compliance Audits for 2015 using the Reliability Standard Requirements listed in the tables titled "CIP Reliability Standards Subject to WECC Monitoring" and "O&P Reliability Standards Subject to WECC Monitoring" in Section 3 above (collectively, the "Reliability Standards Subject to WECC Monitoring in 2015") as a baseline, as well as an Entity's Registered Functions. A summarized list of CIP and O&P Reliability Standards subject to Audit for 2015 is included in the Reliability Standards Subject to WECC Monitoring – 2015 document on the WECC website. The scope of each audit, however, may be adjusted based on WECC's risk IRA (and ICE if available) of the registered entity.

Annual Self-Certification

As noted in WECC's 2014 CMEP Implementation Plan, the annual Self-Certification for reporting year 2014 will begin December 15, 2014, when WECC will post the Self-Certification Schedule and Forms and send notification to registered entities. The submittal period will run from January 1 through March 2, 2015.

In 2016, WECC will conduct the annual Self-Certification for reporting year 2015. WECC will post the Self-Certification Schedule and Forms and send the Self-Certification notification to registered entities on December 15, 2015. The notification will inform Entities of the reporting period (January 1 through December 31, 2015) and the submittal period (January 1 through March 1, 2016), as well as provide information on the Reliability Standard Requirements covered. Subject to an entity's Registered Functions, the Reliability Standards Requirements for Self-Certification will be determined, in part, by those listed in the tables titled "CIP Reliability Standards Subject to Regional Monitoring" and "O&P Reliability Standards Subject to Regional Monitoring" in Section 3 above. In addition, Reliability Standard Requirements listed in the table titled "Additional Reliability Standards Subject to Self-Certification" below is included to make up the Self-Certification baseline. A summarized list of Reliability Standards subject to Self-Certification for 2015 is included in the Reliability Standards Subject to WECC Monitoring – 2015 document on the WECC website. The

scope of each Self-Certification, however, may be adjusted based on WECC's IRA (and ICE if available) of the registered entity.

WECC may also validate the accuracy of Self-Certification submittals of Compliant, Not Applicable and/or Do Not Own through various analyses, including sending data requests to registered entities for randomly selected Self-Certifications for certain Reliability Standard Requirements and Registered Functions.

Additional Reliability Standards Subject to Self-Certification		
Regional Risk Focus Area	**Justification**	**Standard & Requirement**
Repeat Violations	Reliability Standard Requirements with repeat violations over the most recent 12-month period can be one indication of the possibility of increased risk. These Standard Requirements are included in addition to those listed in the tables in Section 3 titled "CIP Reliability Standards Subject to Regional Monitoring" and "O&P Reliability Standards Subject to Regional Monitoring" to form the baseline of Reliability Standard Requirements subject to Self-Certification for reporting year 2015.	CIP-002 R4 CIP-003 R2 CIP-004 R3 CIP-005 R5 CIP-006 R2 CIP-006 R6 CIP-007 R9 CIP-009 R5 EOP-001 R5 FAC-008 R2 FAC-008 R3 FAC-010 R1 FAC-010 R4 FAC-010 R3 IRO-010 R3 PER-005 R1 PRC-005 R1 VAR-001 E.A.14 VAR-002 R3 VAR-002 R2

Periodic Data Submittals (PDS)

As part of the CMEP, registered entities must submit Periodic Data Submittals (PDS) on schedules required by applicable Reliability Standards, or as established by NERC, or on an as-needed basis where requested by WECC. These Reliability Standards are listed in the table below titled Reliability Standards Subject to Periodic Data Submittal. A summarized list at the Sub-Requirement level is also included in the Reliability Standards Subject to WECC Monitoring - 2015 on the WECC website.

Reliability Standards Subject to Periodic Data Submittal	
Justification	**Standard & Requirement**
These Reliability Standards include requirements for registered entities with applicable Registered Functions to submit data on a periodic basis as indicated in the Requirement or relevant Sub-Requirement.	BAL-001-1 R1 BAL-001-1 R2 BAL-002-1 R1 BAL-002-1 R2 BAL-002-1 R3 BAL-002-1 R4 BAL-002-1 R5 BAL-002-1 R6 BAL-003-0.1b R1.2 BAL-006-2 R4 COM-002-2 R2 EOP-004-2 R2 FAC-003-3 R1 FAC-003-3 R2 FAC-003-3 R6 FAC-003-3 R7 IRO-006-WECC-1 R1 IRO-006-WECC-1 R2 PRC-004-2.1a R3 PRC-004-WECC-1 R3 PRC-021-1 R1 PRC-023-3 R5 PRC-023-3 R6 TPL-002-0b R3 TPL-003-0b R3 TPL-004-0a R2 VAR-002-WECC-1 R1 VAR-002-WECC-1 R2 VAR-501-WECC-1 R1 VAR-501-WECC-1 R2

2015 Audit Schedule

Note that the WECC audit schedule may be revised from time to time during 2015. Thus, the "2015 Audit Schedule" shown below for both on-site and off-site audits applies only as of November, 2014. The most up-to-date audit schedule, including all revisions and updates, is on the WECC's website here: WECC 2015 Audit Schedule. The on-line schedule should be consulted to ensure accuracy as this 2015 IP will not be re-published and re-posted to reflect each change to the audit schedule during 2015.

2015 Audit Schedule	
NCR #	**Registered Entity**
NCR05335	Public Utility District No. 1 of Snohomish County
NCR11458	RockTenn
NCR10292	Shiloh Wind Project 2, LLC
NCR05402	Southwest Transmission Cooperative, Inc.
NCR05321	Platte River Power Authority
NCR05441	US Bureau of Reclamation
NCR05441	US Bureau of Reclamation
NCR10310	Brush Cogeneration Partners
NCR10311	Colorado Energy Management - BCP
NCR10347	Panoche Energy Center LLC
NCR11150	GenOn Delta
NCR10289	Peak Reliability
NCR05282	NorthWestern Corporation
NCR05153	Eugene Water & Electric Board
NCR05106	Colorado Springs Utilities
NCR05465	Western Area Power Administration - Sierra Nevada Region
NCR05430	Transmission Agency of Northern California
NCR10323	Midway Peaking, LLC
NCR11054	South Feather Power Project
NCR10350	Windy Flats Partners, LLC
NCR10030	Tri-State Generation and Transmission Association, Inc. - Reliability
NCR11226	Intermountain Rural Electric Association
NCR05377	San Diego Gas & Electric
NCR05315	Pend Oreille County Public Utility District No. 1
NCR10348	Sunray Operating Services, LLC
NCR10349	EthosEnergy Group
NCR10345	Three Buttes Windpower LLC
NCR05030	Black Hills Corporation
NCR05206	Klickitat County PUD
NCR05163	NextEra Energy Resources, LLC
NCR05191	Idaho Power Company
NCR05366	Rocky Mountain Reserve Group
NCR05281	Northwest Power Pool Reserve Sharing Group
NCR10378	Colorado Energy Management - MPC
NCR05464	Western Area Power Administration - Rocky Mountain Region
NCR05023	Basin Electric Power Cooperative

2015 Audit Schedule	
NCR #	**Registered Entity**
NCR05315	Pend Oreille County Public Utility District No. 1
NCR05299	Pacific Gas and Electric Company
NCR05398	Southern California Edison - Transmission & Distribution Business Unit
NCR10396	Otay Mesa Energy Center, LLC
NCR11104	NAES Corporation - Harvest Wind Project
NCR05377	San Diego Gas & Electric
NCR05299	Pacific Gas and Electric Company
NCR05048	California Independent System Operator
NCR03036	Trans Bay Cable LLC

5. Compliance Outreach

WECC conducts seminars and workshops for Registered Entities to assist them in their compliance activities. The seminars and workshops are important learning exercises for those subject to Reliability Standards. During 2015, WECC will continue its outreach efforts to provide education, seminars, workshop and panel discussions to increase registered entities' awareness of and understanding of Reliability Standards. A few of WECC's outreach efforts are as follows:

Compliance Outreach Activities	
Outreach Activity	**Anticipated Date**
Compliance User Group (CUG)/Critical Infrastructure Protection User Group (CIPUG)	January 27-29, 2015 Anaheim, CA
Compliance User Group (CUG)/Critical Infrastructure Protection User Group (CIPUG)	June 2-4, 2015 Portland, OR
Compliance User Group (CUG)/Critical Infrastructure Protection User Group (CIPUG)	October 13-15, 2015 San Diego, CA
CIP 101 Seminar	Sept. 9-10, 2015 Salt Lake City, UT
CIP Low Impact Assets Seminar	Feb. 3-5, 2015 Salt Lake City, UT
WECC Open Webinar	Third Thursdays of most months
Compliance 101 Webinar	Three times a year prior to CUG/CIPUG

Monthly Open Webinars

Since many of the questions the WECC Compliance Staff receives are very similar, WECC answers questions in an open forum for greater efficiency. WECC Compliance Subject Matter Experts participate on this webinar and respond to questions. In fairness to everyone on the call, WECC does not address entity-specific questions and issues.

Compliance User Group (CUG)

The CUG meeting provides in-depth, in-person, and detailed training and education through structured lecture and presentation, panels of experts, interactive dialog in an open forum, direct question and answer sessions and invaluable networking opportunities. Workshops cover the entire compliance sphere with focus reflecting the attendees' and industries' issues. These meetings provide direct access to the

WECC Compliance management team, staff, and Subject-Matter Experts. Participants may also attend telephonically or via webinar.

Critical Infrastructure Protection User Group (CIPUG)

The mission of the CIPUG is to provide an open forum for the exchange of information regarding the WECC Compliance Program's enforcement of mandatory CIP Standards in the Western Interconnection. Its meetings are structured similarly to those of the Compliance User Group, and it is a forum for WECC to provide information regarding NERC and WECC CIP activities and related training and workshops for registered entities on an as-needed basis.

Information for these workshops and seminars (and others as they are finalized) and the dates on which they are scheduled to occur will be posted on the WECC website.

Appendix B - Compliance Assessment Report

Compliance Assessment Process for Events and Disturbances

The ERO encourages registered entities to perform an initial compliance assessment (CA) concurrent with the registered entity's event review and analysis. When completing a CA, the registered entity should follow these steps:

1. Refer to the causes and contributing factors of the event as determined by the registered entity's events analysis process.
2. Identify all applicable NERC Reliability Standards and Requirements that may have been implicated by the causes and contributing factors of the event.
3. After reviewing the facts and circumstances of the event, develop conclusions that are relevant to step 2 above as they apply to the applicable NERC Reliability Standards Requirements.
4. Self-report any findings of noncompliance to the RE per the CMEP procedures.
5. Provide a copy of its CA report to the RE Compliance organization. The CA should be accompanied by the separate Event Analysis Report, "Brief Report," or similar document that provides sufficient information for the RE to understand the event.

Sample Compliance Assessment Report Template

Event Cause or Contributing Factor	Applicable Reliability Standards and Requirements	Details of CA Efforts	Findings
Cause–Example 1	AAA-000-0 R 1	1. Identify the process used to assess compliance with this Requirement. 2. Identify any evidence that demonstrates compliance 3. Identify any evidence that suggests noncompliance	Finding conclusion
Equipment failure of a high side transformer—cleared along with two transmission lines.	TOP-002-2a R6. Each BA and TOP shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional and local reliability Requirements	Established transfer limits were followed such that the event did not result in instability. The limit for operating across this internal interface is established in the RC. "XYZ Interface All Lines In Stability Guide" (document provided)	No findings of noncompliance

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP V5 Curriculum

Updated: May 12, 2015

100 – Standard-Specific Training			
Standard	**Resource Title and Link**	**Owner**	**Date**
CIP-002-5.1 BES Cyber System Categorization	Low Impact BES Cyber Systems: Slides (see pp. 21-64)	NERC	April 2015
	BES Cyber Systems Grouping: Slides	NERC	April 2015
	CIP-002-5.1 BES Cyber System Categorization: Slides	NPCC	March 2015
	Low Impact BES Cyber Systems: Slides	NERC	February 2015
	CIP-002-5.1: Slides	SERC	February 2015
	Identifying Low Impact BES Assets: Slides	WECC	February 2015
	Compliance Approach for CIP-002-5.1: Newsletter Article, P. 11	RF	January 2015
	Standard Application Guide: CIP-002-5.1: PDF	MRO	January 2015
	CIP-002-5.1, R1: Slides | Recording	RF	October 2014
	Identifying BES Cyber Systems: Zip File	SPP-RE	October 2014
CIP-003-5 Security Management Controls	Transition to CIP-003-6: Slides	NPCC	March 2015
	CIP-003 R2: Low Impact Assets: Slides	SERC	February 2015
	CIP-003-7 R2 Low Impact Assets (LIA) Update: Slides	WECC	January 2015
CIP-004-5.1 Personnel & Training	CIP-004-5 Highlights: Slides	NPCC	March 2015
CIP-005-5	Compliance Approach for CIP-005-5 R1: Newsletter Article, P. 8	RF	April 2015

100 – Standard-Specific Training			
Standard	**Resource Title and Link**	**Owner**	**Date**
Electronic Security Perimeter(s)	CIP-005-5: Slides	NPCC	March 2015
	CIP-005-5 Lessons Learned: Slides	WECC	January 2015
	CIP-005-5: Coming to an ESP near you: Slides	SERC	October 2014
	CIP-005-5: Slides | Recording	RF	October 2014
CIP-006-5 Physical Security of BES Cyber Systems	CIP-006-5 Highlights: Physical Security of BES Cyber Systems: Slides	NPCC	April 2015
	CIP-006 Version 5: Slides	SERC	October 2014
	CIP-006: Slides | Recording	RF	October 2014
CIP-007-5 System Security Management	CIP 007 -5: Transition to Version 5: Slides	NPCC	March 2015
	CIP-007-7: Systems and Security Management Best Practices: Slides	WECC	January 2015
	CIP 101: CIP-007-6: Slides	WECC	September 2014
CIP-008-5 Incident Reporting and Response Planning	Transition to CIP-008-5: Slides	NPCC	March 2015
	CIP-008-5, 009-5, & TFEs: Slides	WECC	September 2014
CIP-009-5 Recovery Plans for BES Cyber Systems	CIP-009-5: Recovery Plans for BES Cyber Systems: Slides	NPCC	March 2015
	CIP-009-6: Recovery Plans for BES Cyber Systems: Slides	RF	January 2015
	CIP-008-5, 009-5, & TFEs: Slides	WECC	September 2014
CIP-010-1 Configuration Change Management and	CIP-010-2 Configuration Management and Vulnerability Assessment: Slides	NPCC	March 2015
	CIP-010-5: Configuration Change Management and Vulnerability Assessments: Slides	SERC	October 2014

100 – Standard-Specific Training			
Standard	**Resource Title and Link**	**Owner**	**Date**
Vulnerability Assessments	CIP-010: Slides | Recording	RF	October 2014
	CIP-010-1 R1 & R2: Configuration Change Management: Recording	SPP-RE	June 2014
CIP-011-1 Cyber Security - Information Protection	CIP-011-2 Information Protection: Slides	NPCC	March 2015
	CIP-011-2: Information Protection: Slides	RF	February 2015
CIP-014-1 Physical Security	CIP-014-1 Physical Security Update: Slides	SERC	April 2015
	CIP-014-X Update: Slides	RF	April 2015
	CIP-014 Physical Security: What We Know So Far: Slides	NPCC	March 2015
	Physical Security Standard Implementation: Web Page	NERC	February 2015
	CIP-014: Risk Assessment and Third-Party Verifications: PDF	NERC	February 2015
	Physical Security Reliability Standard Implementation: Slides	NERC	February 2015
	CIP-014-1: Update and Implementation: Slides	WECC	January 2015
	CIP-014-1 Physical Security: Slides	TRE	October 2014
	CIP-014: Next Steps from an Auditor's Perspective: Slides	WECC	October 2014

200 – Compliance and Enforcement Considerations		
Resource Title and Link	**Owner**	**Date**
Risk-Based CMEP Activities and V5 Examples: Slides	NERC	April 2015
CIP V5 Update: Slides	SERC	April 2015

CIP Update: Slides	SPP-RE	March 2015
V3 to V5 Transition Mapping: Spreadsheet	WECC	December 2014
Application of Risk-based CMEP Concepts for CIP V5: PDF	NERC	October 2014
CIP Version 5 Implementation Plan Dates: PDF	NERC	August 2014
Enforcement Approach to CIP V5 under RAI: Slides	NERC	March 2014

300 – Lessons Learned, Guidance, and FAQs		
Resource Title and Link	**Owner**	**Date**
CIP Version 5 Workshop: Recording	NERC	April 2015
CIP Version 5 Transition Program Update: Slides (see pp. 1-20)	NERC	April 2015
Results of CIPv5 Pilot Program - Dayton Power & Light: Slides (see pp. 65-81)	NERC	April 2015
CIP Version 5 Workshop: Recording	NERC	March 2015
TFEs Under V5: Slides	NPCC	March 2015
NERC Virtualization Summit: Recording	NERC	February 2015
CIP Version 5 Workshop: Recording	NERC	February 2015
Critical Infrastructure Protection 101: Slides	MRO	February 2015
CIP Version 3 to Version 5 Transition: Slides	MRO	February 2015
CIP Version 5 Pilot Study – Lessons Learned: Slides	WECC	January 2015
Technical Feasibility Exception – WebCDMS Updates: Slides	TRE	December 2014
CIP V5 Implementation Study: SMUD's Experience: Slides	WECC	October 2014
CIP Version 5 Transition: Slides | Recording	RF	October 2014
CIP Version 5 Transition Guidance: Slides	NERC	September 2014
CIP Standards Version 5 in 15 Minutes or Less: Slides	SERC	September 2014
CIP Version 5 Transition Guidance: Slides	SPP-RE	September 2014

CIP Workshops and Training Events (Updated May 4, 2015)			
Date	**Sponsor**	**Topic/Registration Link**	**Location/Event Resources**
January 24	WECC	CIPUG	Event Resources Coming Soon
February 4–5	WECC	Low Impact Workshop	Event Resources Coming Soon
February 11–12	MRO	V5 Workshop	Event Resources
February 17–18	MRO	V5 Workshop	Event Resources
February 19	NERC	Virtualization Summit	Event Resources
February 19	WECC	WECC Compliance Open Webinar	Event Resources Coming Soon
February 24–25	FRCC	V5 Workshop	Event Resources
February 24–26	NERC	Small Group Advisory Sessions/ CIP V5 Workshop	Event Resources
February 24–25	SERC	Compliance Seminar	Event Resources
February 25	SERC	Small Entity Seminar – CIP	Event Resources
March 10	SERC	Sharing Best Practices: An Entity's Approach to Internal Controls	Event Resources
March 10–11	SPP-RE	Spring Compliance Workshop	Event Resources
March 24–25	NPCC	CIP Version 5 Transition Seminar	Event Resources
March 24–26	NERC	Small Group Advisory Sessions/ CIP V5 Workshop	Event Resources
April 14–16	FRCC	Compliance Workshop	Event Resources
April 16–17	RF	CIP V5 Workshop	Event Resources
April 21–23	NERC	Small Group Advisory Sessions/ CIP V5 Workshop	Event Resources
May 11–13	FRCC	CIP Workshop	Tampa, FL
May 14	TRE	CIP Workshop	Austin, TX
May 19	NPCC	Compliance and Standards Workshop	Newport, RI
June 2–3	SPP-RE	CIP Workshop	Kansas City, MO
June 4	WECC	CIP User Group	Portland, OR
July 7–8	WECC	V5 Meeting – Low Impact	San Francisco, CA
September 9–10	WECC	CIP 101	TBD
September 29–30	SPP-RE	Fall Compliance Workshop	Dallas, TX
September 29–30	SERC	CIP Compliance Seminar	Charlotte, NC
October 1–2	RF	CIP V5 Workshop	Cleveland, OH
October 15	WECC	CIP User Group	Tempe, AZ
October 27–28	SERC	Compliance Seminar	Charlotte, NC
November 10–12	FRCC	Fall Compliance Workshop	Tampa, FL

As they become available, additional registration links and information about additional events will be added to this document.

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151 FERC ¶ 61,134
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-11-000]

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

(May 14, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events). Proposed Reliability Standard TPL-007-1 establishes requirements for certain entities to assess the vulnerability of their transmission systems to geomagnetic disturbance events (GMDs), which occur when the sun ejects charged particles that interact and cause changes in the earth's magnetic fields. Entities that do not meet certain performance requirements, based on the results of their vulnerability assessments, must develop a plan to achieve the requirements. The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, submitted the proposed Reliability Standard for Commission approval in response to a Commission directive in Order No. 779. In addition, the Commission proposes to direct that NERC develop modifications to the benchmark GMD event definition set forth in Attachment 1 of the proposed Reliability Standard so that the

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definition is not based solely on spatially-averaged data. The Commission also proposes to direct NERC to submit a work plan, and subsequently one or more informational filings, that address specific GMD-related research areas.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

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151 FERC ¶ 61,134
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events — Docket No. RM15-11-000

NOTICE OF PROPOSED RULEMAKING

(May 14, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events). Proposed Reliability Standard TPL-007-1 establishes requirements for certain entities to assess the vulnerability of their transmission systems to geomagnetic disturbance events (GMDs), which occur when the sun ejects charged particles that interact and cause changes in the earth's magnetic fields. Entities that do not meet certain performance requirements, based on the results of their vulnerability assessments, must develop a plan to achieve the requirements. The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted the proposed Reliability Standard for Commission approval in response to a Commission directive in Order No. 779.[2] The

[1] 16 U.S.C. 824o.

[2] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 78 FR 30,747 (May 23, 2013), 143 FERC ¶ 61,147, *reh'g denied*, 144 FERC ¶ 61,113 (2013).

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Commission also proposes to approve one definition for inclusion in the NERC Glossary of Terms submitted by NERC as well as the proposed Reliability Standard's associated violation risk factors and violation severity levels, implementation plan, and effective dates.[3]

2. In addition, as discussed below, the Commission proposes to direct NERC to develop modifications to Reliability Standard TPL-007-1 and submit informational filings to address certain issues described herein.

3. Geomagnetic disturbances are considered to be "high impact, low frequency" events.[4] In other words, while the probability of occurrence of a severe geomagnetic disturbance may be low, a geomagnetic disturbance of sufficient magnitude could have potentially severe consequences to the reliable operation of the Bulk-Power System.[5] Such events could cause widespread blackouts and cause damage to equipment that could result in sustained system outages.[6] On that basis, it is important that NERC, planning

[3] NERC, Glossary of Terms Used in NERC Reliability Standards (April 2015) (NERC Glossary), *available at* http://www.nerc.com/files/glossary_of_terms.pdf.

[4] *See* NERC Petition at 3; *see also* NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

[5] Order No. 779, 143 FERC ¶ 61,147 at P 15 (quoting NERC comment that "as a high-impact, low frequency event, GMDs pose a unique threat to Bulk-Power System reliability, and NERC is committed to working with stakeholders and the Commission to address these challenges consistent with its responsibilities as the ERO").

[6] *Id.* PP 3, 16 (citing NERC, 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at 69 (February 2012) (GMD Interim Report); Oak Ridge National Laboratory, Electromagnetic Pulse: Effects

(continued ...)

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coordinators, transmission planners, transmission owners and generator owners take appropriate actions to prepare to withstand potentially harmful geomagnetic disturbances. For that reason, Order No. 779 required NERC to identify what severity GMD events (i.e., benchmark GMD events) responsible entities will have to assess, and that NERC should technically support its choice. In the proposed reliability standard, NERC set the benchmark GMD event as a "1-in-100 year" event.

4. We believe, based on information available at this time, that the provisions of proposed Reliability Standard TPL-007-1 are just and reasonable and address the specific parameters for the Second Stage GMD Reliability Standards on geomagnetic disturbance events, as set forth in Order No. 779. For example, the proposed Reliability Standard requires responsible entities to maintain system models needed to complete "GMD Vulnerability Assessments" (Requirements R1 and R2),[7] have criteria for acceptable system steady state voltage performance during a benchmark GMD event (Requirement R3), and complete a GMD Vulnerability Assessment once every 60 calendar months, based on the benchmark GMD event definition described in Attachment 1 of the proposed Reliability Standard (Requirement R4). Further, if an applicable entity

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on the U.S. Power Grid: Meta-R-319 at page 1-14, Tables 4-1, 4-2, 4-3 (discussing at-risk transformers) (January 2010)).

[7] NERC proposes to define the term GMD Vulnerability Assessment to mean a "documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances." *See* NERC Petition, Ex. B (Implementation Plan for TPL-007-1) at 1.

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concludes, based on the GMD Vulnerability Assessment, that its system does not meet specified performance requirements, it must develop a corrective action plan that addresses how the performance requirements will be met (Requirement R7). We propose to determine that the framework of the proposed Reliability Standard, as outlined above, is just and reasonable and provides a basis for approval. We believe that, when tested against an appropriate benchmark GMD event, compliance with the proposed Reliability Standard should provide adequate protection for an applicable entity's system to withstand a geomagnetic disturbance based on a 1-in-100 year GMD event design.

5. Our primary concerns with the proposed Reliability Standard pertain to the benchmark GMD event described in Attachment 1 of the proposed Reliability Standard. While there is limited historical geomagnetic data and the scientific understanding of geomagnetic disturbance events is still evolving, we have concerns regarding the proposed Reliability Standard's heavy reliance on spatial averaging. Thus, while proposing to approve proposed Reliability Standard TPL-007-1, we also propose to direct NERC to make several modifications to better ensure that, going forward, the study and benchmarking of geomagnetic disturbance events are based on a more complete set of data and a reasonable scientific and engineering approach. Further, we propose specific revisions to Requirement R7 of the proposed Reliability Standard to ensure that, when an applicable entity identifies the need for a corrective action plan, the entity acts in a timely manner.

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I. Background

A. Section 215 and Mandatory Reliability Standards

6. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced in the United States by the ERO, subject to Commission oversight, or by the Commission independently.[8]

B. GMD Primer

7. GMD events occur when the sun ejects charged particles that interact and cause changes in the earth's magnetic fields.[9] Once a solar particle is ejected, it can take between 17 to 96 hours (depending on its energy level) to reach earth.[10] A geoelectric field is the electric potential (measured in volts per kilometer (V/km)) on the earth's surface and is directly related to the rate of change of the magnetic fields.[11] The geoelectric field has an amplitude and direction and acts as a voltage source that can cause geomagnetically-induced currents (GICs) to flow on long conductors, such as

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[8] 16 U.S.C. 824o(e).

[9] GMD Interim Report at i-ii. On April 30, 2015, the Space Weather Operations, Research, and Mitigation Task Force, under the auspices of the National Science and Technology Council, sought comment on a draft 2015 National Space Weather Strategy, which is designed to "articulate high-level strategic goals for enhancing National preparedness to space weather events." *National Science and Technology Council; National Space Weather Strategy*, 80 FR 24,296 (Apr. 30, 2015).

[10] GMD Interim Report at ii.

[11] *Id.*

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transmission lines.[12] The magnitude of the geoelectric field amplitude is impacted by local factors such as geomagnetic latitude and local earth conductivity.[13] Geomagnetic latitude is the proximity to earth's magnetic north and south poles, as opposed to earth's geographic poles. Local earth conductivity is the ability of the earth's crust to conduct electricity at a certain location to depths of hundreds of kilometers down to the earth's mantle. Local earth conductivity impacts the magnitude (i.e., severity) of the geoelectric fields that are formed during a GMD event by, all else being equal, a lower earth conductivity resulting in higher geoelectric fields.[14]

C. Order No. 779

8. In Order No. 779, the Commission directed NERC, pursuant to FPA section 215(d)(5), to develop and submit for approval proposed Reliability Standards that address the impact of geomagnetic disturbances on the reliable operation of the Bulk-Power System. The Commission based its directive on the potentially severe, wide-spread impact on the reliable operation of the Bulk-Power System that can be caused by GMD events and the absence of existing Reliability Standards to address GMD events.[15]

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[12] *Id.*

[13] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 4.

[14] *Id.*

[15] Order No. 779, 143 FERC ¶ 61,147 at P 3.

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9. Order No. 779 directed NERC to implement the directive in two stages. In the first stage, the Commission directed NERC to submit, within six months of the effective date of Order No. 779, one or more Reliability Standards (First Stage GMD Reliability Standards) that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System.[16]

10. In the second stage, the Commission directed NERC to submit, within 18 months of the effective date of Order No. 779, one or more Reliability Standards (Second Stage GMD Reliability Standards) that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole. The Commission directed that the Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System.[17] Order No. 779 explained that, if the assessments identify potential impacts from benchmark GMD events, the Reliability Standards should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System

[16] *Id.* P 2.

[17] *Id.*

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equipment, or otherwise, as a result of a benchmark GMD event. The Commission directed that the development of this plan could not be limited to considering operational procedures or enhanced training alone, but should, subject to the potential impacts of the benchmark GMD events identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment.[18] Order No. 779 observed that these strategies could, for example, include automatically blocking GICs from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, isolating certain equipment that is not cost effective to retrofit, or a combination thereof.

D. Order No. 797

11. In Order No. 797, the Commission approved Reliability Standard EOP-010-1 (Geomagnetic Disturbance Operations).[19] NERC submitted Reliability Standard EOP-010-1 for Commission approval in compliance with the Commission's directive in Order No. 779 corresponding to the First Stage GMD Reliability Standards. In Order No. 797-A, the Commission denied the Foundation for Resilient Societies' (Resilient Societies) request for rehearing of Order No. 797. The Commission stated that the rehearing

[18] *Id.*

[19] *Reliability Standard for Geomagnetic Disturbance Operations*, Order No. 797, 79 FR 35,911 (June 25, 2014), 147 FERC ¶ 61,209, *reh'g denied*, Order No. 797-A, 149 FERC ¶ 61,027 (2014).

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request "addressed a later stage of efforts on geomagnetic disturbances (i.e., NERC's future filing of Second Stage GMD Reliability Standards) and [that Resilient Societies] may seek to present those arguments at an appropriate time in response to that filing."[20] In particular, the Commission stated that GIC monitoring requirements should be addressed in the Second Stage GMD Reliability Standards.[21]

E. NERC Petition and Proposed Reliability Standard TPL-007-1

12. On January 21, 2015, NERC petitioned the Commission to approve proposed Reliability Standard TPL-007-1 and its associated violation risk factors and violation severity levels, implementation plan, and effective dates.[22] NERC also submitted a proposed definition for the term "Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment" for inclusion in the NERC Glossary. NERC maintains that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC further contends that the proposed

[20] Order No. 797-A, 149 FERC ¶ 61,027 at P 2.

[21] *Id.* P 27 (stating that the Commission continues "to encourage NERC to address the collection, dissemination, and use of geomagnetic induced current data, by NERC, industry or others, in the Second Stage GMD Reliability Standards because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models").

[22] Proposed Reliability Standard TPL-007-1 is not attached to this notice of proposed rulemaking (NOPR). The proposed Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM15-11-000 and on the NERC website, www.nerc.com. NERC submitted an errata on February 2, 2015 containing a corrected version of Exhibit A (Proposed Reliability Standard TPL-007-1).

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Reliability Standard satisfies the directive in Order No. 779 corresponding to the Second Stage GMD Reliability Standards.[23]

13. NERC states that proposed Reliability Standard TPL-007-1 applies to planning coordinators, transmission planners, transmission owners and generation owners who own or whose planning coordinator area or transmission planning area includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher. NERC explains that the applicability criteria for qualifying transformers in the proposed Reliability Standard is the same as that for the First Stage GMD Reliability Standard in EOP-010-1, which the Commission approved in Order No. 797.

14. The proposed Reliability Standard contains seven requirements.

15. Requirement R1 requires planning coordinators and transmission planners to determine the individual and joint responsibilities in the planning coordinator's planning

[23] We note that Resilient Societies has submitted to NERC, pursuant to Section 8.0 of the NERC Standards Process Manual, an appeal alleging certain procedural errors in the development of proposed Reliability Standard TPL-007-1. *See* NERC Rules of Procedure, Attachment 3A (Standards Process Manual), Section 8.0 (Process for Appealing an Action or Inaction). The appeal is currently pending NERC action. On May 12, 2015, Resilient Societies submitted a request for stay of the proceedings in Docket No. RM15-11-000, asking that the Commission refrain from issuing a notice of proposed rulemaking until NERC acts on Resilient Societies' appeal. We deny Resilient Societies' request. We see no irreparable harm in issuing a proposal for public comment as we do today. Rather, we will consider any necessary issues pertaining to the appeal before or in a final rule issued in this proceeding.

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area for maintaining models and performing studies needed to complete the GMD Vulnerability Assessment required in Requirement R4.[24]

16. Requirement R2 requires planning coordinators and transmission planners to maintain system models and GIC system models needed to complete the GMD Vulnerability Assessment required in Requirement R4.

17. Requirement R3 requires planning coordinators and transmission planners to have criteria for acceptable system steady state voltage limits for their systems during the benchmark GMD event described in Attachment 1 (Calculating Geoelectric Fields for the Benchmark GMD Event).

18. Requirement R4 requires planning coordinators and transmission planners to conduct a GMD Vulnerability Assessment every 60 months using the benchmark GMD event described in Attachment 1 to the proposed Reliability Standard. The benchmark GMD event is based on a 1-in-100 year frequency of occurrence and is composed of four elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) a scaling factor to account for local geomagnetic latitude; (3) a scaling factor to account for local earth conductivity; and (4) a reference geomagnetic field time series or wave shape to facilitate time-domain

[24] Proposed Reliability Standard TPL-007-1, Requirements R2, R3, R4, R5, and R7 refer to planning coordinators and transmission planners as "responsible entities."

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analysis of GMD impact on equipment.[25] The product of the first three elements is referred to as the regional geoelectric field peak amplitude.[26]

19. Requirement R5 requires planning coordinators and transmission planners to provide GIC flow information, to be used in the transformer thermal impact assessment required in Requirement R6, to each transmission owner and generator owner that owns an applicable transformer within the applicable planning area.

20. Requirement R6 requires transmission owners and generator owners to conduct thermal impact assessments on solely and jointly owned applicable transformers where the maximum effective GIC value provided in Requirement R5 is 75 amperes per phase (A/phase) or greater.

21. Requirement R7 requires planning coordinators and transmission planners to develop corrective action plans if the GMD Vulnerability Assessment concludes that the system does not meet the performance requirements in Table 1 (Steady State Planning Events).

II. Discussion

22. Pursuant to section 215(d) of the FPA, the Commission proposes to approve Reliability Standard TPL-007-1 as just, reasonable, not unduly discriminatory or

[25] *See* Proposed Reliability Standard TPL-007-1, Att. 1; s*ee also* NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

[26] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

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preferential, and in the public interest. The proposed Reliability Standard addresses the directives in Order No. 779 corresponding to the development of the Second Stage GMD Reliability Standards. Proposed Reliability Standard TPL-007-1 does this by requiring applicable Bulk-Power System owners and operators to conduct initial and on-going vulnerability assessments regarding the potential impact of a benchmark GMD event on the Bulk-Power System as a whole and on Bulk-Power System components.[27] In addition, the proposed Reliability Standard requires applicable entities to develop and implement corrective action plans to mitigate any identified vulnerabilities.[28] Potential mitigation strategies identified in the proposed Reliability Standard include, but are not limited to, among other things, the installation, modification, or removal of transmission and generation facilities and associated equipment.[29] Accordingly, proposed Reliability Standard TPL-007-1 constitutes an important step in addressing the risks posed by GMD events to the Bulk-Power System.

23. While proposed Reliability Standard TPL-007-1 addresses the Order No. 779 directives, pursuant to FPA section 215(d)(5), the Commission proposes to direct NERC to develop modifications to the Reliability Standard concerning: (1) the calculation of the reference peak geoelectric field amplitude component of the benchmark GMD event

[27] *See* Order No. 779, 143 FERC ¶ 61,147 at PP 67, 71.

[28] *Id.* P 79.

[29] *Id.*

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definition; (2) the collection of GIC monitoring and magnetometer data; and (3) deadlines for completing corrective action plans and the mitigation measures called for in corrective action plans. In addition, to improve the understanding of GMD events generally and address the specific research areas discussed below, the Commission proposes to direct that NERC submit informational filings. These proposals are discussed in greater detail below.

24. The Commission seeks comments from NERC and interested entities on these proposals.

A. Benchmark GMD Event Definition

NERC Petition

25. NERC states that the purpose of the benchmark GMD event is to "provide a defined event for assessing system performance during a low probability, high magnitude GMD event."[30] NERC explains that the benchmark GMD event represents "the most severe GMD event expected in a 100-year period as determined by a statistical analysis of recorded geomagnetic data."[31] The benchmark GMD event definition is used in the GMD Vulnerability Assessments and thermal impact assessment requirements of the proposed Reliability Standard.

[30] NERC Petition at 15.

[31] *Id.*

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26. As noted above, NERC states that the benchmark GMD event definition has four elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) a scaling factor to account for local geomagnetic latitude; (3) a scaling factor to account for local Earth conductivity; and (4) a reference geomagnetic field time series or wave shape to facilitate time-domain analysis of GMD impact on equipment.[32]

27. The standard drafting team determined that a 1-in-100 year GMD event would cause an 8 V/km reference peak geoelectric field amplitude at 60 degree geomagnetic latitude using Québec's earth conductivity.[33] The standard drafting team stated that:

> the reference geoelectric field amplitude was determined through statistical analysis using … field measurements from geomagnetic observatories in northern Europe and the reference (Quebec) earth model …. The Quebec earth model is generally resistive and the geological structure is relatively well understood. The statistical analysis resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km …. The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years.[34]

28. The standard drafting team explained that it used field measurements taken from the IMAGE magnetometer chain, which covers Northern Europe, for the period 1993-2013 to calculate the reference peak geoelectric field amplitude used in the benchmark

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[32] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

[33] *Id.*

[34] *Id.* (footnotes omitted).

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GMD event definition.[35] As described in NERC's petition, the standard drafting team "spatially averaged" four different station groups of IMAGE data, each spanning a square area of approximately 500 km (roughly 310 miles) in width.[36] The standard drafting team justified the use of spatial averaging by stating that the proposed Reliability Standard is designed to "address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse."[37]

29. NERC states that the benchmark GMD event includes scaling factors to enable applicable entities to tailor the reference peak geoelectric field to their specific location for conducting GMD Vulnerability Assessments. NERC states that the scaling factors in the benchmark GMD event definition are applied to the reference peak geoelectric field

[35] *Id.* at 8. The International Monitor for Auroral Geomagnetic Effects (IMAGE) consists of 31 magnetometer stations in northern Europe maintained by 10 institutes from Estonia, Finland, Germany, Norway, Poland, Russia, and Sweden. *See* IMAGE website, *available at* http://space.fmi.fi/image/beta/?page=home#.

[36] As applied by the standard drafting team, spatial averaging refers to the averaging of geoelectric field amplitude readings within a given area. NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 9.

[37] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 9.

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amplitude to adjust the 8 V/km value for different geomagnetic latitudes and earth conductivities.[38]

30. The standard drafting team also identified a reference geomagnetic field time series from an Ottawa magnetic observatory during a 1989 GMD event that affected Québec.[39] The standard drafting team used this time series to estimate a geoelectric field, represented as a time series (i.e., 10-second values over a period of days), that is expected to occur at 60 degree geomagnetic latitude during a 1-in-100 year GMD event. NERC explains that this time series is used to facilitate time-domain analysis of GMD impacts on equipment.[40]

Discussion

31. The Commission proposes to approve proposed Reliability Standard TPL-007-1, including the proposed benchmark GMD event definition submitted by NERC. However, pursuant to FPA section 215(d)(5) , the Commission proposes to direct that NERC develop modifications to the benchmark GMD event definition set forth in Attachment 1 of the proposed Reliability Standard so that the definition is not based solely on spatially-averaged data. The Commission also seeks comment from NERC and other interested entities regarding the scaling factor used to account for geomagnetic

[38] NERC Petition at 18-19.

[39] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 15-16.

[40] *Id.* at 5-6.

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latitude in the benchmark GMD event definition. The Commission also proposes to direct NERC to submit a work plan, and subsequently one or more informational filings, that address the specific issues discussed below.

32. The benchmark GMD event definition proposed by NERC complies with the directive in Order No. 779 requiring that the Second Stage GMD Reliability Standards identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System. Order No. 779 did not specify the severity of the storm or define the characteristics of the benchmark GMD event. Instead, the Commission directed NERC, through the standards development process, to define the benchmark GMD events. Consistent with the guidance provided in Order No. 779, the benchmark GMD event definition proposed by NERC addresses the potential widespread impact of a severe GMD event, while taking into consideration the variables of geomagnetic latitude and local earth conductivity.[41] Accordingly, we propose to approve the definition submitted by NERC. Nonetheless, while acceptable as consistent with FPA section 215 and the Order No. 779 directives, we believe that the

[41] *See* Order No. 779, 143 FERC ¶ 61,147 at P 71 ("the benchmark GMD events should be based on factors that may include, but are not limited to, varying severity of the GMD … duration, geographic footprint of the GMD, how the GMD's intensity varies with latitude, system configuration, and the orientation of the magnetic fields produced by the GMD); *see also id*. P 70 ("[GMD] vulnerability assessments would be based on uniform criteria (e.g., geographic location and geology) but the values for such criteria would be entity-specific").

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benchmark GMD event definition should be improved through the proposed revision and research discussed below.

33. First, the proposed Reliability Standard's exclusive use of spatial averaging to calculate the reference peak geoelectric field amplitude could underestimate the impact of a 1-in-100 year GMD event, which was the design basis arrived upon by the standard drafting team. NERC states that the benchmark GMD event "expands upon work conducted by the NERC GMD Task Force in which 1-in 100 year geoelectric field amplitudes were calculated from a well-known source of dense high-resolution geomagnetic data commonly used in space weather research [i.e., IMAGE data]."[42] However, the application of spatial averaging significantly reduces the reference peak geoelectric field amplitude using the IMAGE data compared with a prior analysis of nearly the same data set. As noted in the NERC petition, the GMD Interim Report described a study that used the same IMAGE magnetometers and data as the standard drafting team for the period 1993-2006.[43] That study calculated a 1-in-100 year peak geoelectric amplitude of 20 V/km for Québec.[44] The study calculated a significantly higher figure (20 V/km versus 8 V/km) using similar data as the standard drafting team because, instead of averaging geoelectric field values occurring simultaneously over a

[42] NERC Petition at 17.

[43] GMD Interim Report at 22.

[44] *Id.*

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large geographic area, the study cited by the GMD Interim Report used the magnitude of the geoelectric amplitude in individual geomagnetic observatories.

34. Based on our review of NERC's petition, it does not appear that spatial averaging of geomagnetic fields is discussed in the studies cited by the standard drafting team except in the standard drafting team's GMD Benchmark Event White Paper. In addition, it is unclear how the standard drafting team determined that spatial averaging should be performed using a square area 500 km in width. The GMD Benchmark Event White Paper explains that the IMAGE magnetometers were organized into four groups comprised of squares 500 km wide, and the readings within a group were averaged. The GMD Benchmark Event White Paper also states, citing to the statistical analysis in its Appendix I, that "geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system."[45] While Appendix I of the GMD Benchmark Event White Paper discusses why local geomagnetic disturbances do not have a significant impact on all transformers operating within a square 500 km in width, it does not explain why the standard drafting team chose a square area 500 km in width as opposed to a square with a smaller or larger total area. These questions largely inform our concerns regarding the proposed Reliability Standard's heavy reliance on spatial averaging.

[45] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 4.

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35. The geoelectric field values used to conduct GMD Vulnerability Assessments and thermal impact assessments should reflect the real-world impact of a GMD event on the Bulk-Power System and its components. A GMD event will have a peak value in one or more location(s), and the amplitude will decline over distance from the peak. Only applying a spatially-averaged geoelectric field value across an entire planning area would distort this complexity and could underestimate the contributions caused by damage to or misoperation of Bulk-Power System components to the system-wide impact of a GMD event within a planning area. However, imputing the highest peak geoelectric field value in a planning area to the entire planning area may incorrectly overestimate GMD impacts. Neither approach, in our view, produces an optimal solution that captures physical reality.

36. To address this issue, the Commission proposes to direct NERC to develop modifications to the Reliability Standard so that the reference peak geoelectric field amplitude element of the benchmark GMD event definition is not based solely on spatially-averaged data. For example, NERC could satisfy this proposal by revising the Reliability Standard to require applicable entities to conduct GMD Vulnerability Assessments and thermal impact assessments using two different benchmark GMD events: the first benchmark GMD event using the spatially-averaged reference peak geoelectric field value (8 V/km) and the second using the non-spatially averaged peak

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geoelectric field value found in the GMD Interim Report (20 V/km).[46] The revised Reliability Standard could then require applicable entities to take corrective actions, using engineering judgment, based on the results of both assessments. That is, the applicable entity would not always be required to mitigate to the level of risk identified by the non-spatially averaged analysis; instead, the selection of mitigation would reflect the range of risks bounded by the two analyses, and be based on engineering judgment within this range, considering all relevant information. This proposed revision is consistent with the directive in Order No. 779 that owners and operators develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System.[47] Alternatively, NERC could propose an equally efficient and effective modification that does not rely exclusively on the spatially-averaged reference peak geoelectric field value.[48]

[46] Conducting a GMD Vulnerability Assessment using essentially two measures of the same benchmark GMD events is consistent with Order No. 779 because, in that order, the Commission contemplated that an applicable entity could be required to assess GMD vulnerabilities using multiple benchmark GMD events. Order No. 779, 143 FERC ¶ 61,147 at P 2 ("The Second Stage GMD Reliability Standards must identify 'benchmark GMD events' that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System.").

[47] Order No. 779, 143 FERC ¶ 61,147 at P 2.

[48] For example, responsible entities could calculate GIC flows and resulting Bulk-Power System impacts using models that utilize both spatially averaged and non-spatially averaged peak geoelectric field values to simulate GMD conditions.

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37. The Commission also seeks comment from NERC and other interested entities regarding the scaling factor used in the benchmark GMD event definition to account for differences in geomagnetic latitude. Specifically, the Commission seeks comment on whether, in light of studies indicating that GMD events could have pronounced effect on lower geomagnetic latitudes, a modification is warranted to reduce the impact of the scaling factors.[49]

38. Next, the record submitted by NERC and other available information manifests a need for more data and certainty in the knowledge and understanding of GMD events and their potential effect on the Bulk-Power System. For example, NERC's proposal is based on data from magnetometers in northern Europe, from a relatively narrow timeframe with relatively low solar activity, and with little or no data on concurrent GIC flows. Similarly, the adjustments for latitude and ground conductivity are based on the limited information currently available, but additional data-gathering is needed. To address this

[49] *See*, *e.g.*, Ngwira, C. M., Pulkkinen, A., Kuznetsova, M. M., Glocer, A., "Modeling extreme 'Carrington-type' space weather events using three-dimensional global MHD simulations," 119 Journal of Geophysical Research: Space Physics 4472 (2014) (finding that in Carrington-type events "the region of large induced ground electric fields is displaced further equatorward … [and] thereby may affect power grids … such as [those in] southern states of [the] continental U.S."); Gaunt, C. T., Coetzee, G., "Transformer Failures in Regions Incorrectly Considered to have Low GIC-Risk," 2007 IEEE Lausanne 807 (July 2007) (stating that twelve transformers were damaged and taken out of service in South Africa (at -40 degrees latitude) during a 2003 GMD event).

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limitation on relevant information, we propose to direct that NERC conduct or oversee additional analysis on these issues.[50]

39. In particular, we propose to direct that NERC submit informational filings that address the issues discussed below. In the first informational filing, NERC should submit a work plan indicating how NERC plans to: (1) further analyze the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km); (2) further analyze earth conductivity models by, for example, using metered GIC and magnetometer readings to calculate earth conductivity and using 3-D readings; (3) determine whether new analyses and observations support modifying the use of single station readings around the earth to adjust the spatially averaged benchmark for latitude; and (4) assess how to make GMD data (e.g., GIC monitoring and magnetometer data) available to researchers for study.[51] We propose that NERC submit the work plan within six months of the effective date of a final rule in this proceeding. The work plan submitted by NERC should include a schedule to submit one or more informational

[50] *See, e.g., Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208 (2013) (approving Reliability Standard but directing that NERC perform a study to develop empirical evidence on one input to the "Gallet equation" used to calculate minimum clearances for vegetation).

[51] The Commission seeks comment on the barriers, if any, to public dissemination of GIC and magnetometer readings, including if the dissemination of such data poses a security risk and if any such data should be treated as Critical Energy Infrastructure Information or otherwise restricted to authorized users.

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filings that apprise the Commission of the results of the four additional study areas as well as any other relevant developments in GMD research. Further, in the submissions, NERC should assess whether the proposed Reliability Standard remains valid in light of new information or whether revisions are appropriate.

B. Thermal Impact Assessments

NERC Petition

40. Proposed Reliability Standard TPL-007-1, Requirement R6 requires owners of transformers that are subject to the proposed Reliability Standard to conduct thermal analyses to determine if the transformers would be able to withstand the thermal effects associated with a benchmark GMD event. NERC states that transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 75 A/phase during the benchmark GMD event as determined by an analysis of the system. NERC explains that "based on available power transformer measurement data, transformers with an effective GIC of less than 75 A per phase during the Benchmark GMD Event are unlikely to exceed known temperature limits established by technical organizations."[52]

41. As provided in Requirements R5 and R6, "the maximum GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1" determines whether a transformer satisfies the 75 A/phase threshold. If the 75

[52] NERC Petition at 30.

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A/phase threshold is satisfied, Requirement R6 states, in relevant part, that a thermal impact assessment should be conducted on the qualifying transformer based on the effective GIC flow information provided in Requirement R5.

Discussion

42. The Commission proposes to approve proposed Reliability Standard TPL-007-1, Requirement R6. However, the Commission has two concerns regarding the proposed thermal impact assessment in Requirement R6. These concerns reflect in part the difficulty of replacing large transformers quickly, as reflected in studies, such as an April 2014 report by the Department of Energy that highlighted the reliance in the United States on foreign suppliers for large transformers.[53]

43. First, as discussed in the previous section, the Commission proposes to direct NERC to develop modifications to the Reliability Standard such that the benchmark GMD event definition's reference peak geoelectric field amplitude element does not rely on spatially-averaged data alone. The proposed modification is relevant to thermal impact assessments, as it is relevant to GMD Vulnerability Assessments, because both are ultimately predicated on the benchmark GMD event definition. Indeed, the concern is even greater in this context because a thermal impact assessment assesses the localized

[53] U.S. Department of Energy, Large Power Transformers and the U.S. Electric Grid (April 2014), *available at* http://energy.gov/sites/prod/files/2014/04/f15/LPTStudyUpdate-040914.pdf

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impact of a GMD event on an individual transformer. Thus, we propose to direct NERC to modify the Reliability Standard to require responsible entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments.

44. Second, Requirements R5.1 and R6 provide that the geoelectric field orientation causing the maximum effective GIC value in each transformer should be used to determine if the assessed transformer satisfies the 75 A/phase qualifying threshold in Requirement R6. However, Requirement R6 does not use the maximum GIC-producing orientation to conduct the thermal assessment for qualifying transformers (i.e., transformers with an maximum effective GIC value greater than 75A/phase). Instead, Requirement R6 uses the effective GIC time series described in Requirement R5.2 to conduct the thermal assessment on qualifying transformers.[54] The Commission seeks comment from NERC as to why qualifying transformers are not assessed for thermal impacts using the maximum GIC-producing orientation. NERC should address whether, by not using the maximum GIC-producing orientation, the required thermal impact assessments could underestimate the impact of a benchmark GMD event on a qualifying transformer.

[54] *See also* NERC Petition, Ex. E (White Paper on Transformer Thermal Impact Assessment) at 8-9.

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C. Monitoring Devices

NERC Petition

45. Proposed Reliability Standard TPL-007-1, Requirement R2 requires responsible entities to "maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s)." NERC states that proposed Reliability Standard TPL-007-1 contains "requirements to develop the models, studies, and assessments necessary to build a picture of overall GMD vulnerability and identify where mitigation measures may be necessary."[55] NERC explains that mitigating strategies "may include installation of hardware (e.g., GIC blocking or monitoring devices), equipment upgrades, training, or enhanced Operating Procedures."[56]

Discussion

46. The Commission proposes to direct NERC to develop revisions to Reliability Standard TPL-007-1 requiring installation of monitoring equipment (i.e., GIC monitors and magnetometers) to the extent there are any gaps in existing GIC monitoring and magnetometer networks, which will ensure a more complete set of data for planning and operational needs. Alternatively, we seek comment on whether NERC itself should be responsible for installation of any additional, necessary magnetometers while affected

[55] NERC Petition at 13.

[56] *Id.* at 32.

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entities would be responsible for installation of additional, necessary GIC monitors. As part of NERC's work plan, we propose to direct that NERC identify the number and location of current GIC monitors and magnetometers in the United States to assess whether there are any gaps.

47. NERC maintains that the installation of monitoring devices could be part of a mitigation strategy. We agree with NERC regarding the importance of GIC and magnetometer data. As the Commission stated in Order No. 779, the tools for assessing GMD vulnerabilities are not fully mature.[57] Data from monitors are needed to validate the analyses underlying NERC's proposed Reliability Standard and the analyses to be performed by affected entities.[58] GIC monitors also can facilitate real-time adjustments to grid operations during GMD events, to maintain reliability and prevent significant equipment damage, by enhancing situational awareness for grid operators. For example, PJM's operating procedures for GMDs are triggered when GICs are above 10 A for 10 minutes at either of two specified locations, and confirmed by other sources of information.[59]

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[57] Order No. 779, 143 FERC ¶ 61,147 at P 68.

[58] *See*, *e.g.*, *Disturbance Monitoring and Reporting Requirements Reliability Standard*, 80 FR 22,441 (Apr. 16, 2015), 151 FERC ¶ 61,042 (2015) (notice of proposed rulemaking proposing to approve Reliability Standard PRC-002-2 requiring the collection of disturbance monitoring data).

[59] *See* PJM Manual 13 (Emergency Operations), Revision 57, at 55 (2015).

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48. Accordingly, rather than wait to install necessary monitoring devices as part of a corrective action plan, GIC and magnetometer data should be collected by applicable entities at the outset to validate and improve system models and GIC system models, as well as improve situational awareness. To be clear, we are not proposing that every transformer would need its own GIC monitor or that every entity would need its own magnetometer. Instead, we are proposing the installation and collection of data from GIC monitors and magnetometers in enough locations to provide adequate analytical validation and situational awareness. We propose that NERC's work plan use this criterion in assessing the need and locations for GIC monitors and magnetometers.

49. Cost recovery is potentially available for costs associated with or incurred to comply with proposed Reliability Standard TPL-007-1, including for the purchase and installation of monitoring devices.[60] The Commission seeks comment on whether it should adopt a policy specifically allowing recovery of these costs.

[60] Order No. 779, 143 FERC ¶ 61,147 at P 14 n.20 (stating that "nothing precludes entities from seeking cost recovery if needed"); *see Extraordinary Expenditures Necessary to Safeguard National Energy Supplies*, 96 FERC ¶ 61,299, at 61,129 (2001) (stating that the Commission "will approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure in response to the heightened state of alert. Companies may propose a separate rate recovery mechanism, such as a surcharge to currently existing rates or some other cost recovery method"); *see also Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052, at P 28 (2004) (affirming and clarifying that "the policy extends to the recovery of prudent reliability expenditures, including those for vegetation management, improved grid management and monitoring equipment, operator training and compliance with NERC standards").

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D. Corrective Action Plan Deadlines

NERC Petition

50. Proposed Reliability Standard TPL-007-1, Requirement R7 provides that:

> Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that their System does not meet the performance requirements of Table 1 shall develop a Corrective Action Plan addressing how the performance requirements will be met ….

NERC explains that the NERC Glossary defines corrective action plan to mean, "A list of actions and an associated timetable for implementation to remedy a specific problem."[61] Requirement R7.3 states that the corrective action plan shall be provided within "90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need."

Discussion

51. The Commission proposes to direct that NERC revise Reliability Standard TPL-007-1 to include deadlines concerning the development and implementation of corrective action plans under Requirement R7.

52. In accordance with Order No. 779 directives, Requirement R7 requires applicable entities to develop and implement measures when vulnerabilities from a benchmark

[61] NERC Petition at 31.

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GMD event are identified.[62] However, Requirement R7 does not establish deadlines for developing or implementing corrective action plans. Requirement R7 only requires responsible entities to distribute corrective action plans within 90 days of completion to certain registered entities. By contrast, other NERC Reliability Standards include deadlines for developing corrective action plans, such as Reliability Standard PRC-006-2 (Automatic Underfrequency Load Shedding) and Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements). In addition, by definition, a corrective action plan includes "an associated timetable for implementation" of a remedy.[63] Consistent with the definition of corrective action plan and the other NERC Reliability Standards, the Commission proposes to direct that NERC modify Reliability Standard TPL-007-1 to require corrective action plans to be developed within one year of the completion of the GMD Vulnerability Assessment.

53. A corrective action plan is defined in the NERC Glossary as "[a] list of actions and an associated timetable for implementation to remedy a specific problem." Because of the complexities surrounding GMDs and the uncertainties about mitigation techniques, the time needed to implement a corrective action plan may be difficult to determine. At

[62] Order No. 779, 143 FERC ¶ 61,147 at P 2 ("If the assessments identify potential impacts from benchmark GMD events, the Reliability Standards *should* require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event.").

[63] NERC Glossary at 26.

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the same time, the absence of reasonable deadlines for completion of corrective actions may risk significant delay before identified corrective actions are started or finished. The Commission, therefore, proposes to direct NERC to modify the Reliability Standard to require a deadline for non-equipment mitigation measures that is two years following development of the corrective action plan and a deadline for mitigation measures involving equipment installation that is four years following development of the corrective action plan. The Commission recognizes that there is little experience with installing equipment for GMD mitigation and thus we are open to proposals that may differ from our proposal, particularly from any entities with experience in this area.

54. We seek comments from NERC and interested entities on these proposals. Further, we seek comment on appropriate alternative deadlines and whether there should be a mechanism that would allow NERC to consider, on a case-by-case basis, requests for extensions of required deadlines.

E. Minimization of Load Loss and Curtailment

NERC Petition

55. Proposed Reliability Standard TPL-007-1, Requirement R4 states that each responsible entity "shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months." Requirement R4.2 further states that the "study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1."

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56. NERC maintains that Table 1 sets forth requirements for system steady state performance. NERC explains that Requirement R4 and Table 1 "address assessments of the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the loss of devices due to GIC impacts."[64] Table 1 provides, in relevant part, that load loss and/or curtailment are permissible elements of the steady state:

> Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Discussion

57. The Commission seeks comment from NERC regarding the provision in Table 1 that "Load loss or curtailment of Firm Transmission Service should be minimized." Because the term "minimized" does not represent an objective value, the provision is potentially subject to interpretation and assertions that the term is vague and may not be enforceable. Similarly, use of the modifier "should" might indicate that minimization of load loss or curtailment is only an expectation or a guideline rather than a requirement.

58. The Commission seeks comment from NERC that explains how the provision in Table 1 regarding load loss and curtailment will be enforced, including: (1) whether, by

[64] NERC Petition at 39.

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using the term "should," Table 1 requires minimization of load loss or curtailment, or both; and (2) what constitutes "minimization" and how it will be assessed.

F. Violation Risk Factors and Violation Severity Levels

59. Each requirement of proposed Reliability Standard TPL-007-1 includes one violation risk factor and has an associated set of at least one violation severity level. NERC states that the ranges of penalties for violations will be based on the sanctions table and supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines.

60. The Commission proposes to approve the violation risk factors and violation severity levels submitted by NERC, for the requirements in Reliability Standard TPL-007-1, consistent with the Commission's established guidelines.[65]

G. Implementation Plan and Effective Dates

61. NERC proposes a phased, five-year implementation period.[66] NERC maintains that the proposed implementation period is necessary: (1) to allow time for entities to develop the required models; (2) for proper sequencing of assessments because thermal impact assessments are dependent on GIC flow calculations that are determined by the responsible planning entity; and (3) to give time for development of viable corrective action plans, which may require applicable entities to "develop, perform, and/or validate

[65] *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

[66] NERC Petition, Ex. B (Implementation Plan for TPL-007-1).

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new or modified studies, assessments, procedures … [and because] [s]ome mitigation measures may have significant budget, siting, or construction planning requirements."[67]

62. The proposed implementation plan states that Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after Commission approval. For Requirement R2, NERC proposes that the requirement shall become effective on the first day of the first calendar quarter that is 18 months after Commission approval. NERC proposes that Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after Commission approval. NERC proposes that Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after Commission approval. And for Requirement R3, Requirement R4, and Requirement R7, NERC proposes that the requirements shall become effective on the first day of the first calendar quarter that is 60 months after Commission approval.

63. The Commission proposes to approve the implementation plan and effective dates submitted by NERC. However, given the serial nature of the requirements in the proposed Reliability Standard, we are concerned about the duration of the timeline associated with any mitigation stemming from a corrective action plan. As a result, the Commission seeks comment from NERC and other interested entities as to whether the length of the implementation plan, particularly with respect to Requirements R4, R5, R6, and R7, could be reasonably shortened.

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[67] *Id.* at 2.

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III. Information Collection Statement

64. The collection of information contained in this notice of proposed rulemaking is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[68] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[69]

65. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

66. We solicit comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically, the Commission asks that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

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[68] 44 U.S.C. 3507(d).

[69] 5 CFR 1320.11 (2014).

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Public Reporting Burden: The Commission proposes to approve Reliability Standard TPL-007-1 and the associated implementation plan, violation severity levels, and violation risk factors, as discussed above. Proposed Reliability Standard TPL-007-1 will impose new requirements for transmission planners, planning coordinators, transmission owners, and generator owners. Proposed Reliability Standard TPL-007-1, Requirement R1 requires planning coordinators, in conjunction with transmission planner, to identify the responsibilities of the planning coordinator and transmission planner in the planning coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessments. Proposed Requirements R2, R3, R4, R5, and R7 refer to the "responsible entity, as determined by Requirement R1," when identifying which applicable planning coordinators or transmission planners are responsible for maintaining models and performing the necessary study or studies. Proposed Requirement R2 requires that the responsible entities maintain models for performing the studies needed to complete GMD Vulnerability Assessments, as required in proposed Requirement R4. Proposed Requirement R3 requires responsible entities to have criteria for acceptable system steady state voltage performance during a benchmark GMD event. Proposed Requirement R4 requires responsible entities to complete a GMD Vulnerability Assessment of the near-term transmission planning horizon once every 60 calendar months. Proposed Requirement R5 requires responsible entities to provide GIC flow information to transmission owners and generator owners that own an applicable bulk electric system power transformer in the planning area. This information is necessary for applicable transmission owners and generator owners to conduct the

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thermal impact assessments required by proposed Requirement R6. Proposed Requirement R6 requires applicable transmission owners and generator owners to conduct thermal impact assessments where the maximum effective GIC value provided in proposed Requirement R5, Part 5.1 is 75 A/phase or greater. Proposed Requirement R7 requires responsible entities to develop a corrective action plan when its GMD Vulnerability Assessment indicates that its system does not meet the performance requirements of Table 1 – Steady State Planning Events. The corrective action plan must address how the performance requirements will be met, must list the specific deficiencies and associated actions that are necessary to achieve performance, and must set forth a timetable for completion. The Commission estimates the annual reporting burden and cost as follows:

FERC-725N, as modified by the NOPR in Docket No. RM15-11-000 (TPL-007-1 Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events)[70]

[70] Eng.=engineer; RK =recordkeeping (record clerk); PC=planning coordinator; TP=transmission planner; TO=transmission owner; and GO=generator owner.

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	Number of Respondents (1)	Annual Number of Responses per Respondent (2)	Total Number of Responses (1)*(2)=(3)	Average Burden Hours & Cost Per Response [71] (4)	Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)	Cost per Respondent ($) (5)÷(1)
(One-time) Requirement 1	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 4 hrs. ($149.80)	1,089 hrs. (605 Eng., 484 RK); $58,267.55 ($40,141.75 Eng., $18,125.80 RK)	$481.55
(On-going) Requirement 1	121 (PC & TP)	1	121	Eng. 3 hrs. ($199.05); RK 2 hrs. ($74.90)	605 hrs. (363 Eng., 242 RK); $33,147.95 ($24,085.05 Eng., $9,062.90 RK)	$273.95

[71] The estimates for cost per response are derived using the following formula: Burden Hours per Response * $/hour = Cost per Response. The $66.35/hour figure for an engineer and the $37.45/hour figure for a record clerk are based on data on the average salary plus benefits from the Bureau of Labor Statistics obtainable at **Error! Hyperlink reference not valid.**http://bls.gov/ oes/current/naics3_221000.htm and http://www.bls.gov/news.release/ecec.nr0.htm.

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(One-time) Requirement 2	121 (PC & TP)	1	121	Eng. 22 hrs. ($1,459.70); RK 18 hrs. ($674.10)	4840 hrs. (2,662 Eng., 2,178 RK); $258,189.80 ($176,623.70 Eng., $81,566.10 RK)	$2,133.80
(On-going) Requirement 2	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 3 hrs. ($112.35)	968 hrs. (605 Eng., 363 RK); $53,736.10 ($40,141.75 Eng., $13,594.35 RK)	$444.10
(One-time) Requirement 3	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 3 hrs. ($112.35)	968 hrs. (605 Eng., 363 RK); $53,736.10 ($40,141.75 Eng., $13,594.35 RK)	$444.10
(On-going) Requirement 3	121 (PC & TP)	1	121	Eng. 1 hrs. ($66.35); RK 1 hrs. ($37.45)	242 hrs. (121 Eng., 121 RK); $12,559.80 ($8,028.35 Eng., $4,531.45 RK)	$103.80

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(On-going) Requirement 4	121 (PC & TP)	1	121	Eng. 27 hrs. ($1,791.45); RK 21 hrs. ($786.45)	5,808 hrs. (3,267 Eng., 2,541 RK); $311,919.85 ($216,765.45 Eng., $95,154.40 RK)	$2,277.85
(On-going) Requirement 5	121 (PC & TP)	1	121	Eng. 9 hrs. ($597.15); RK 7 hrs. ($262.15)	1936 hrs. (1,089 Eng., 847 RK); $103,975.30 ($72,255.15 Eng., $31,720.15 RK)	$859.30
(One-time) Requirement 6	881 (TO & GO)	1	881	Eng. 22 hrs. ($1,459.70); RK 18 hrs. ($674.19)	35,240 hrs. (19,382 Eng., 15,858 RK); $1,879,957.09 ($1,285,995.70 Eng., $593,961.39 RK)	$2,133.89
(On-going) Requirement 6	881 (TO & GO)	1	881	Eng. 2 hrs. ($132.70); RK 2 hrs. ($74.90)	3,524 hrs. (1,762 Eng., 1762 RK); $182,895.60 ($116,908.70 Eng., $65,986.90 RK)	$207.60

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(On-going) Requirement 7	121 (PC & TP)	1	121	Eng. 11 hrs. ($729.85); RK 9 hrs. ($337.05)	2,420 hrs. (1,331 Eng., 1,089 RK); $129,094.90 ($88,311.85 Eng., $40,783.05 RK)	$1,066.90
TOTAL			**2851**		**57,640[72] hrs. (31,792 Eng., 25,848 RK); $3,077,480.04 ($2,109,399.20 Eng., $968,080.84 RK)**	

Title: FERC-725N, Mandatory Reliability Standards: TPL Reliability Standards

Action: Proposed Additional Requirements.

OMB Control No: 1902-0264.

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: One time and on-going.

Necessity of the Information: The Commission has reviewed the requirements pertaining to proposed Reliability Standard TPL-007-1 and has made a determination that the

[72] Of the 57,640 total burden hours, 42,137 hours are one time burden hours, and 15,503 hours are on-going annual burden hours.

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proposed requirements of this Reliability Standard are necessary to implement section 215 of the FPA. Specifically, these requirements address the threat posed by GMD events to the Bulk-Power System and conform to the Commission's directives regarding development of the Second Stage GMD Reliability Standards, as set forth in Order No. 779.

Internal review: The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

67. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

68. Comments concerning the information collections proposed in this notice of proposed rulemaking and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference FERC-725N and OMB Control No. 1902-0264 in your submission.

IV. Environmental Analysis

69. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

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on the human environment.[73] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[74] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

70. The Regulatory Flexibility Act of 1980 (RFA)[75] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[76] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from a standard based on megawatt hours).[77] Under SBA's new size standards, planning coordinators, transmission planners,

[73] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

[74] 18 CFR 380.4(a)(2)(ii).

[75] 5 U.S.C. 601-12.

[76] 13 CFR 121.101.

[77] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77,343 (Dec. 23, 2013).

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transmission owners, and generator owners are likely included in one of the following categories (with the associated size thresholds noted for each):[78]

- Hydroelectric power generation, at 500 employees
- Fossil fuel electric power generation, at 750 employees
- Nuclear electric power generation, at 750 employees
- Other electric power generation (e.g., solar, wind, geothermal, biomass, and other), at 250 employees
- Electric bulk power transmission and control,[79] at 500 employees

71. Based on these categories, the Commission will use a conservative threshold of 750 employees for all entities.[80] Applying this threshold, the Commission estimates that there are 440 small entities that function as planning coordinators, transmission planners, transmission owners, and/or generator owners. However, the Commission estimates that only a subset of such small entities will be subject to the proposed Reliability Standard given the additional applicability criteria in the proposed Reliability Standard (i.e., to be subject to the requirements of the proposed Reliability Standard, the applicable entity must own or must have a planning area that contains a large power transformer with a high side, wye grounded winding with terminal voltage greater than 200 kV).

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[78] 13 CFR 121.201, Sector 22, Utilities.

[79] This category covers transmission planners and planning coordinators.

[80] By using the highest number threshold for all types of entities, our estimate conservatively treats more entities as "small entities."

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72. Proposed Reliability Standard TPL-007- 1 enhances reliability by establishing requirements that require applicable entities to perform GMD Vulnerability Assessments and to mitigate any identified vulnerabilities. The Commission estimates that each of the small entities to whom the proposed Reliability Standard TPL-007-1 applies will incur one-time compliance costs of $5,193.34 and annual ongoing costs of $5,233.50.

73. The Commission does not consider the estimated cost per small entity to impose a significant economic impact on a substantial number of small entities. Accordingly, the Commission certifies that the proposed Reliability Standard will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

74. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**. Comments must refer to Docket No. RM15-11-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

75. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

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76. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC, 20426.

77. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

78. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

79. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

80. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference

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Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

Kimberly D. Bose,
Secretary.

Document Content(s)

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

State of Reliability 2015

May 2015

RELIABILITY | ACCOUNTABILITY

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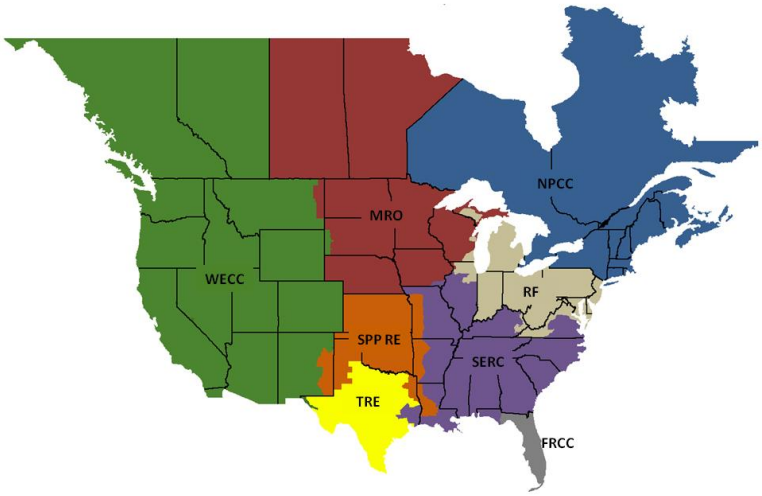
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Notice

This report presents metrics and trends derived from the data available at the time of publication and may be modified pending further review and analysis.

Executive Summary

The *State of Reliability 2015* report presents NERC's independent view of ongoing bulk power system (BPS) trends via data compiled through December 2014 to objectively provide an integrated view of reliability performance. The key findings and recommendations serve as technical input to NERC's risk assessment, Reliability Standards project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection efforts. The analysis of BPS performance developed as part of this report provides a reference of historical reliability, offers analytical insights regarding industry action, and enables the identification and prioritization of specific steps that can be taken to manage risks that have an effect on reliability.

The analysis of available data provided in the report demonstrates that, excluding weather effects, BPS reliability remained within defined performance objectives to provide an Adequate Level of Reliability (ALR).[1] Weather continues to be a significant stress factor on BPS reliability, specifically impacting generator performance. Several of the most important reliability performance findings were (1) there was no loss of load due to cyber or physical security events in 2014; (2) average transmission outage severity declined; (3) protection system misoperations continue to escalate risk in Qualified Events, and (3) there was a significant decrease in unplanned transmission outages that resulted in a loss of load. Excluding the impact of extreme weather, BPS performance for events that can be controlled by industry action demonstrated that the reliability risk of non-weather events is manageable.

In its mission to ensure the reliability of the BPS, NERC carries out multiple initiatives and assessments. One such initiative is the development and maintenance of performance metrics. This report introduces new performance metrics in two key areas: compliance and security. When performance metrics were first introduced in 2010, the Key Compliance Monitoring Index (KCMI) was developed to track the impact of "Standard-driven" risks of compliance violations. Due to the number of Reliability Standards modifications, it became difficult to update the changing set of requirements while maintaining meaningful tracking of the compliance violation data that could provide informative trends. Two metrics are proposed to replace the retired KCMI. One metric relies on ERO Enforcement staff's determination of the risk of a potential violation, and the other metric is a quarterly count of the number of reported Reliability Standards noncompliances with observed reliability impact.

NERC also developed a set of security performance metrics. The metrics include the total number of Reportable Cyber Security Incidents[1] and physical security reportable events[2] that occur over time and identify how many of these incidents have resulted in a loss of load. They also include Electricity Sector Information Sharing and Analysis Center (ES-ISAC) membership and Incident Bulletins published by the ES-ISAC based on information voluntarily submitted by ES-ISAC member organizations. These metrics provide lagging and leading indicators for security performance applicable to reliable BES operation.

The goal of the *State of Reliability 2015* report is to quantify risk and performance, highlight areas for improvement, and reinforce and measure success in controlling risks to reliability. The ongoing work in NERC's Performance Analysis staff, working with the Performance Analysis Subcommittee, provides a foundation for these risk assessments, which is documented in this report.

[1] Definition of "Adequate Level of Reliability," http://www.nerc.com/comm/Other/Adequate_Level_of_Reliability_Task_Force_ALRTF_DL/Final_Documents_Posted_for_Stakeholders and Board of Trustee Review/10_04_12_ALR_Definition_clean.pdf (The assessment objectives relate to planning assessments, which are not covered in the report).

[1] Ref. NERC Glossary of Terms: "A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity."

[2] Reportable events are defined in Reliability Standard EOP-004-2 Event Reporting, Attachment 1.

Chapter 1 – Key Findings

2014 Reliability Performance

The 2014 reliability performance continued to remain high, sustaining the positive trends documented in the review of 2013 performance in the *State of Reliability 2014* report. In late 2012, NERC adopted a revised definition of Adequate Level of Reliability, which forms the basis for the reliability indicators that are used as metrics to evaluate the performance of the BES. The five performance objectives, two assessment objectives, and associated expected performance outcomes were developed to encompass NERC's responsibility to ensure reliability of the BES.[2] The severity risk index (SRI)[3] and metrics measuring the ALR characteristics indicate that the BPS is within defined performance objectives. Based on the data and analysis presented within this report, the following key findings were identified:

- Weather continues to stress BPS reliability
- No load loss due to cyber or physical security events[4]
- Decline of average transmission outage severity
- Significant decrease in unplanned transmission outages resulting in loss of load
- Stable frequency response trend
- Protection system misoperations trending lower, but continue to escalate risk in Qualified Events[5]
- Continued decline of the use of Energy Emergency Alert Level 3 (declared by Balancing Authorities (BAs) or Load-Serving Entities (LSEs) when they are deficit in resources)

Key Finding 1: Weather Continues to Stress BPS Reliability

The analysis of SRI in Chapter 3 and the metrics in Chapter 4 demonstrate that BPS reliability remained within the ALR performance objectives. Weather continues to be a significant stress factor on BPS reliability, leading primarily to generator outages and deratings. Load-loss events were not the primary driver of high SRI days during 2014. All of the top-10 most severe events in 2014 were initiated or exacerbated by weather. There were three high-stress days (i.e., days with an SRI greater than 5.0) in 2014. Two of the days were associated with the polar vortex;[6] the remaining high-stress day was associated with an extreme weather event in California. The calculated SRI for all but two of the 10 highest SRI days for the year was driven by generation performance and, to a lesser extent, transmission outage performance, and did not involve a significant degree of load loss. While the BPS is expected to perform at a high level during weather events, system performance must continue to be examined in light of extreme weather. To the extent that weather is determined as a large impact to day-to-day and extreme-day performance, other metrics that report on BPS reliability (specifically load-loss events) that retain weather impacts should be developed. Excluding the impact of these extreme days, BPS performance for events that can be controlled by industry action was consistently above the ALR performance objectives, demonstrating that the reliability risk of non-weather events is manageable. Chapter 3 contains further discussion on this topic.

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[2] Definition of "Adequate Level of Reliability," http://www.nerc.com/comm/Other/Adequate_Level_of_Reliability_Task_Force_ALRTF_DL/Final_Documents_Posted_for_Stakeholders and Board of Trustee Review/10_04_12_ALR_Definition_clean.pdf (The assessment objectives relate to planning assessments, which are not covered in the report).

[3] SRI is a "stress" index, measuring risk impact from events resulting in transmission loss, generation loss, and load loss.

[4] A Reportable Cyber Security Incident is defined as "A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity." A reportable physical event is defined in Reliability Standard EOP-004-2 Event Reporting, Attachment 1.

[5] A Qualified Event is an event that meets a category description in the Electric Reliability Organization Event Analysis Process, found at http://www.nerc.com/pa/rrm/ea/EA Program Document Library/Final_ERO_EA_Process_V2.1.pdf.

[6] http://www.nerc.com/pa/rrm/January 2014 Polar Vortex Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

Recommendation
NERC and industry should develop metrics that provide insight into weather impacts on BPS performance, especially during load-loss events.

Key Finding 2: No Load Loss Due to Cyber or Physical Security Events

Analysis of the newly developed security performance metric data showed that no Reportable Cyber Security Incidents or physical security reportable events resulted in loss of load on the BPS in 2014. As recommended in the *State of Reliability 2014* report, the NERC Performance Analysis Subcommittee (PAS) collaborated with the BES Security Metrics Working Group (BESSMWG) to develop security performance metrics. The BESSMWG developed an initial set of five metrics, presented in Chapter 9.

NERC Actions to Support BES Security

NERC is committed to analyzing and advising industry on cybersecurity compromises that could lead to impacts on reliability. On November 22, 2013, FERC approved Version 5 of the critical infrastructure protection cybersecurity standards (CIP Version 5), representing significant progress in mitigating cyber risks to the BPS. NERC initiated a program to support industry transition directly from the currently enforceable CIP Version 3 standards to CIP Version 5. The goal of the transition program is to improve industry's understanding of the technical security requirements for CIP Version 5, as well as the expectations for compliance and enforcement.

The Electricity Sector Information Sharing and Analysis Center (ES-ISAC) establishes situational awareness, incident management, coordination, and communication capabilities within the electricity sector through timely, reliable, and secure information exchange. The ES-ISAC, in collaboration with the Department of Energy and the Electricity Sector Coordinating Council (ESCC), serves as the primary security communications channel for the electricity sector and enhances the sector's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents. ES-ISAC member organizations include NERC registered entities and others in the electricity sector. A strategic review of the ES-ISAC is ongoing, and expected to conclude in the summer of 2015.

As part of its ongoing training and education efforts, NERC conducted its second industry-wide grid security exercise, GridEx II, in November 2013. The exercise, a coordinated cyber and physical attack on the BPS, promoted coordination and highlighted urgent issues facing the industry. A report[7] summarizing the exercise highlights recommendations and lessons learned for industry to use when preparing for and responding to cyber and physical threats, vulnerabilities, and incidents. The results are also incorporated into strategic action by NERC's Critical Infrastructure Protection Committee (CIPC) and the ESCC. Planning for GridEx III, which is scheduled for late 2015, has begun. The scenario will include robust cyber and physical threats to the BPS to exercise crisis response and recovery, improve crisis communications, gather lessons learned, and engage senior industry and government leaders.

On March 7, 2014, FERC issued an order directing NERC to address physical security risks and vulnerabilities of critical facilities on the BPS. In response to the order, Reliability Standard CIP-014-1 was adopted by the Board and subsequently filed with and approved by FERC, to become effective on October 1, 2015. FERC directed NERC to remove the term "widespread" from the standard or, alternatively, propose modifications to the Reliability Standard that address FERC's concerns. While NERC is proceeding through the Standards Development Process to incorporate these refinements, implementation of the standard is underway.

[7] http://www.nerc.com/pa/CI/CIPOutreach/GridEX/GridEx II After Action Report.pdf.

Recommendations

- NERC, with support from CIPC, should deploy the security metrics presented in Chapter 9.
- Working with industry and forums such as the North American Transmission Forum (NATF), NERC should analyze information from these security metrics and consider development of additional metrics that could provide valuable information on cybersecurity.
- NERC, working jointly with the ESCC, should conclude expeditiously the strategic review of the ES-ISAC.

Key Finding 3: Decline of Average Transmission Outage Severity

The average transmission outage severity continued to decrease in 2014. After realizing a significant decrease from 2012 to 2013, it reduced again from 2013 to 2014, based on analysis of year-over-year changes in calculated transmission outage severity of TADS events by Initiating Cause Code (ICC). This analysis, presented in Appendix A, shows continuing positive performance in the average transmission outage severity for each ICC and for the 2012–2014 dataset. Events initiated by the ICCs of Misoperations and Failed AC Substation Equipment remained high in total transmission outage severity and were the greatest contributors to transmission outage severity relative risk.

NERC Actions to Support Reducing Misoperations

NERC actions to address misoperations are addressed in Key Finding 6.

NERC Actions to Support Reducing the Risk of Failed AC Substation Equipment

In 2014, NERC produced a report investigating reliability issues related to ac substation equipment failures,[8] with recommendations on bus configuration evaluations, breaker lubrication practices, service advisory tracking, and proactive equipment replacement.

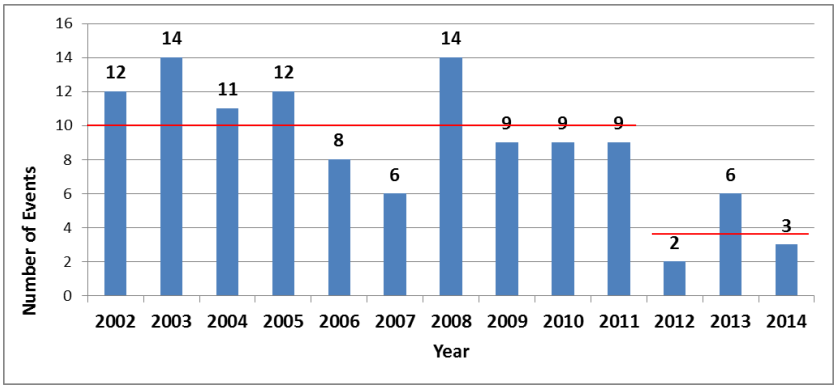
Recommendations

- NERC, working with the NATF, should evaluate the failure rate of circuit breakers and determine the impact of bus configuration on ac transmission circuit outages.
- Entities should evaluate the impact of breaker failures on system performance when choosing bus configurations for new installations or modifying existing substations.
- NERC, working with IEEE and other applicable industry forums, should develop a consistent method for the collection and distribution of ac substation equipment failure data.

[8] http://www.nerc.com/comm/PC/AC Substation Equipment Task Force ACSETF/Final_ACSETF_Report.pdf.

Key Finding 4: Significant Decrease in Unplanned Transmission Outages Resulting in Loss of Load

Analysis of unplanned transmission outage data shows that the number of BPS transmission-related events resulting in loss of firm load from 2002 to 2011 was relatively constant (average of 10 events per year), then dropped significantly over the last three years to an average of less than four per year. Metric M-2 measures BPS transmission-related events resulting in the loss of load, excluding weather-related outages. The analysis of data for this metric is presented in Chapter 4.



NERC Actions to Support Continued Reduction of Unplanned Transmission Outages Resulting in Loss of Load

NERC's focus on this metric in past state of reliability reports resulted in a range of actions. NERC Reliability Standard TOP-003-1 – Planned Outage Coordination was developed and required that scheduled generator and transmission outages potentially affecting the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators. Also, Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits requires that System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) are established and consistent with documented methodology. These standards help ensure that the impact on the BPS from unplanned transmission outages is mitigated. Finally, transmission outage events that meet the definition of a Qualified Event in NERC's Event Analysis Process are evaluated for root causes to derive potential lessons learned that are shared with industry.

Key Finding 5: Stable Frequency Response Trend

From 2012 to 2014, the Eastern, Western, ERCOT, and Québec Interconnections have shown steady frequency response performance, trending above the recommended Interconnection Frequency Response Obligation (IFRO) at all times during the time period studied. NERC annually applies statistical tests to interconnection frequency response datasets,[9] including additional analyses on time of year, load levels, and other attributes. The Eastern Interconnection frequency response has shown a statistically significant positive increase from 2012 to 2014. The Western Interconnection and the ERCOT Interconnection are statistically stable. The Québec Interconnection frequency response experienced a statistically significant decline from 2012 to 2014, but remains well above the calculated IFRO for the Interconnection. It is important to monitor these trends to determine whether any events approach or drop below the IFRO for any Interconnection and to identify any underlying causes and corrective courses of action. The study methods and statistical results are summarized in Chapter 4 and detailed in Appendix D.

NERC Actions to Support Sustained Frequency Response

NERC Reliability Standard BAL-003-1 was approved by the Federal Energy Regulatory Commission (FERC) on January 16, 2014, and has phased-in effective dates of April 1, 2015, and April 1, 2016. The standard requires an annual collection of data for calculating Frequency Bias and for determining compliance with the Frequency Response Obligation (FRO).

[9] Datasets described in the Frequency Response Initiative Report, October 2012 http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

There were no reported Event Analysis Process[10] Qualified Events in 2014 where frequency response performance was cited as a causal factor for initiating or sustaining an event. NERC will examine incidents in 2014 where frequency response was below the IFRO to determine any root causes and actions necessary to improve the frequency response performance.

On February 5, 2015, NERC issued an Industry Advisory on generator governor frequency response.[11] NERC determined that a significant portion of the Eastern Interconnection generator dead bands or governor control settings could inhibit or prevent frequency response. With the exception of nuclear generators, entities with generators greater than 75 MVA were advised to review generator governor and Distributed Control System (DCS) settings to conform to specifications mentioned in the Advisory.

Recommendations

- NERC should monitor the effectiveness of the Industry Advisory on generator governor frequency response on the Eastern Interconnection.
- NERC should assess the impact of BAL-003-1 on frequency response for all Interconnections subsequent to the Reliability Standard's effective dates.
- NERC, with support from the Resources Subcommittee, should identify root causes and any necessary actions for incidents in 2014 where frequency response was less than the IFRO.
- NERC should determine whether additional actions, beyond those currently being pursued in NERC Reliability Standards, are required to maintain and improve frequency response performance.

Key Finding 6: Protection System Misoperations Trending Lower, but Continue to Escalate Risk in Qualified Events

The analysis of data showed that the protection system misoperation rate began to decline in 2014. The majority of protection system misoperations do not lead to Qualified Events;[12] approximately three percent cause or exacerbate the severity of reportable system disturbances. However, those protection system misoperations that do occur can severely increase risk to reliability. For example, more than 68 percent of transmission-related Qualified Events have protection system misoperations associated with them that either initiated the event or caused it to be more severe. The analysis of these data and events are presented in Chapter 4.

NERC Actions to Support Improved Protection System Performance

NERC is completing revisions to a number of Reliability Standards that involve protection systems[13] to improve their performance. These standards are designed to implement a corrective action program in which specific mitigation of misoperation root causes is required. To increase awareness, NERC conducts industry webinars[14] on protection systems and publishes Lessons Learned on how Generator Owners (GOs) and Transmission Owners (TOs) are achieving high levels of protection system performance. In addition, NERC staff analyzed and reported on the top-three protection system misoperation cause codes reported by entities.[15] This analysis sets the stage for NERC and industry action toward protection system misoperation reduction.

[10] http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx
[11] http://www.nerc.com/pa/rrm/bpsa/Alerts DL/2015 Alerts/NERC Alert A-2015-02-05-01 Generator Governor Frequency Response.pdf
[12] A Qualified Event is an event that meets a category description in the Electric Reliability Organization Event Analysis Process, found at http://www.nerc.com/pa/rrm/ea/EA Program Document Library/Final_ERO_EA_Process_V2.1.pdf.
[13] http://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx.
[14] http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf.
[15] http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/NERC Staff Analysis of Reported Misoperations - Final.pdf.

For example, based on reviews of the Qualified Events for protection system misoperations, there are two main causes of incorrectly set ground instantaneous overcurrent elements. The first is an increase in the maximum value of ground fault short circuit current available over time, rendering the ground settings too sensitive. The second is setting the ground instantaneous overcurrent element without enough margin to accommodate short circuit modeling tolerances and other component anomalies.

In its February 10, 2015 Lessons Learned,[16] NERC advised entities to consider reviewing the maximum value of ground fault short circuit current that was used to develop the protection system settings and ensure that the short circuit current available is appropriate. In addition, entities should review their philosophies for setting ground instantaneous overcurrent elements and determine the appropriate percentage of line length to protect with the instantaneous setting.

Recommendations

- Entities should review the maximum value of ground fault short circuit current that was used to develop the protection system settings and ensure that the short circuit current available is appropriate. In addition, entities should review their philosophies for setting ground instantaneous overcurrent elements and determine the appropriate percentage of line length to protect with the instantaneous setting.
- NERC and the Regions should develop training modules on the importance of standard design templates to address design, logic settings, and peer review.
- NERC should work with the Protection System Misoperations Task Force to develop a guideline on quality control to improve protective relay settings.
- NERC and the Regions, in partnership with protection system equipment manufacturers, should develop an industry outreach program that targets specific organizations that have the greatest impact on protection system misoperation reduction.
- NERC should work with microprocessor relay manufacturers to determine whether any technical bulletins or industry alerts should be developed to address protection system equipment failures.
- The NATF, in coordination with NERC, should engage its membership on key topical areas of improvement and develop targeted improvement plans for its members.

Key Finding 7: Use of Energy Emergency Alert Level 3 Continues to Decline

In 2014 there were four Energy Emergency Alert Level 3 (EEA3) events declared, which is fewer than any other year for which data was reported. Of the four EEA3 events, only one resulted in load shed. This event was due to conditions during the polar vortex[17] that resulted in record-low temperatures and high demand. The other three reported EEA3 alerts did not result in loss of load and were generally caused by transmission limitations resulting in a localized area's inability to make use of the reserves that existed within the region.

NERC Actions to Support Evaluation of EEA3 Events

NERC continues to evaluate each reported EEA3 event to determine the potential impact to reliability. As historical data is gathered by NERC on EEAs, trends provide a relative indication of performance measured at a Regional Entity or interconnection level. The issuance of an EEA3 indicates an issue with the real-time adequacy of the electric supply system. It may be due to a lack of fuel or dependence on transmission for imports into a constrained area, not simply a lack of available generation resources. Events that meet the definition of a Qualified Event in

[16] http://www.nerc.com/pa/rrm/ea/Lessons Learned Document. Library/LL20150202_Effects_of_Mutual_Coupling_when_Setting_Ground_Instantaneous_Overcurrent_Elements.pdf.
[17] http://www.nerc.com/pa/rrm/January 2014 Polar Vortex Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

NERC's Event Analysis Process are evaluated for root causes to derive potential lessons learned that are shared with industry.

Chapter 2 – 2014 Year in Review

The *State of Reliability 2015* report gathers data and metrics needed to evaluate the reliability of the BPS. This chapter describes the conditions in which the electric industry operated during 2014 and other environmental, regulatory, and policy-related issues that took place during 2014 to provide context to the observations and data presented in this report.

Reliability Assurance Initiative

The Reliability Assurance Initiative (RAI) was a collaborative, multiyear effort among NERC, the Regional Entities, and industry to enhance the effectiveness of the Compliance Monitoring and Enforcement Program (CMEP). The initiative focused on the development and implementation of a risk-based approach to compliance monitoring and enforcement. This approach focused NERC, the Regional Entities, and industry resources on higher-risk reliability issues. These methods successfully address high-risk issues while also accounting for lesser-risk reliability issues, which continue to be identified, corrected, and tracked.

Further, the approach focuses on how the ERO performs oversight and obtains assurance on compliance with NERC Reliability Standards, and it does so without creating new or additional requirements (beyond those established in Reliability Standards) for registered entities operating the grid. This approach enables the ERO to leverage registered entity management practices in use at registered entities and inform industry of lessons learned by their peers. The emphasis of this initiative shifted at the end of 2014 toward implementation through the Risk-Based Compliance Monitoring and Enforcement Program.

Transition to Critical Infrastructure Protection Version 5

In 2013, FERC approved Version 5 of the Critical Infrastructure Protection Reliability Standards (CIP Version 5), which represent a significant improvement—and change—over the currently effective CIP Version 3 standards. They include new cybersecurity controls and extend the scope of systems to which the CIP Reliability Standards apply.

NERC initiated the CIP Version 5 Transition Program to collaborate with Regional Entities and applicable entities to implement the CIP Version 5 standards in a manner that is timely, effective, and efficient. The goals of the program are to improve industry's understanding of the technical security requirements for CIP Version 5 and clarify the expectations for compliance and enforcement.

In 2014, NERC concluded a nine-month CIP Version 5 implementation study with a representative sample of six responsible entities focused on the technical solutions and processes needed to implement the CIP Version 5 standards. In so doing, NERC, Regional Entities, and responsible entities developed a deeper understanding of compliance and enforcement matters applicable to CIP Version 5.

As anticipated, NERC, the Regional Entities, and the implementation study participants identified a number of issues during the implementation study that called for additional guidance and clarity. To further ensure confidence in the transition to CIP V5, NERC continued working with the Regional Entities and implementation study participants to develop lessons learned and frequently asked question (FAQ) documents on specific issues. As documents are finalized, they will be shared with industry. Working in collaboration with the Regional Entities, implementation study participants, and other stakeholders, NERC also developed a transition guidance document and compatibility tables that compare requirements in CIP Version 5 with requirements in CIP Version 3. In addition, NERC addressed stakeholder concerns with a document that clarifies how the risk-based compliance monitoring and enforcement processes developed under RAI will apply to CIP Version 5.

Risk-Based Registration Initiative

NERC's Risk-Based Registration initiative seeks to ensure that the right entities are subject to the right set of applicable NERC Reliability Standards using a consistent approach to risk assessment and registration across the ERO. In 2014, NERC established the Risk-Based Registration Advisory Group (RBRAG) and the RBRAG technical task force to provide input and advice on the design framework and implementation plan.

The framework includes refined thresholds based on sound technical analysis, risk considerations, and support; reduced NERC Reliability Standard applicability based on sound technical analysis, risk considerations, and support; and clearly defined terms, criteria, and procedures that are risk-based and ensure the reliability of the BPS as outlined in the new BES definition. The proposed enhancements reduce unnecessary burdens while preserving BPS reliability and enable entities to avoid causing or exacerbating instability, uncontrolled separation, or cascading failures.

Polar Vortex Review

As part of NERC's ongoing efforts to identify risks to BPS reliability and to inform stakeholders of the impacts of those risks, NERC reviewed the extreme weather event (polar vortex) that occurred January 6–8, 2014. The *Polar Vortex Review*[18] details how the BPS exhibited its resiliency during the polar vortex, as BPS reliability was maintained despite sustained record-low temperatures occurring over a large geographic area in North America. Many areas experienced daytime-high and overnight-low temperatures that were between 20 and 30 degrees below average, with 49 cities setting new record lows.

North America GOs and TOs responded well to prevent major impacts to the BPS through industry preparations and operational effectiveness. NERC examines the impact of these events to ensure lessons learned and related information are shared to prevent reoccurrences where possible and, most importantly, sustain successful operation and maintenance practices. As expected, key factors during the event included fuel deliverability issues, natural gas pipeline outages, gas service interruptions, frozen electricity and gas equipment, and other extreme cold weather operating challenges.

During the event, grid operators employed techniques such as voltage reduction and demand-side management to ensure that BES reliability was maintained. Only one BA shed firm load during the polar vortex event, which is an indication of a strong overall performance by industry under extremely challenging circumstances.

2014 Long-Term Reliability Assessment

The *2014 Long-Term Reliability Assessment*[19] provided a forward-looking, independent perspective of the resources needed to maintain reliability of the North American BPS over the next 10 years. NERC examined key indicators including load forecasts, expected resources, and transmission additions. The assessment identified three key reliability findings facing industry in the coming years: downward trends in reserve margins, uncertain impacts of environmental rules, and an ongoing resource mix transformation.

In several assessment areas, reserve margins trended downward because of ongoing generation retirements, despite low load growth. Uncertainty remains for a large amount of existing conventional generation that may be vulnerable to retirement resulting from pending regulations, particularly the EPA's proposed Clean Power Plan.

Potential Reliability Impacts from the Proposed Clean Power Plan

[18] http://www.nerc.com/pa/rrm/January 2014 Polar Vortex Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf
[19] http://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/2014LTRA_ERATTA.pdf

A preliminary reliability review of the EPA assumptions and potential reliability impacts of the Environmental Protection Agency's proposed Clean Power Plan under Section 111(d) of the Clean Air Act was completed in November. This assessment, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan*,[20] examined the potential reliability concerns that could result from the proposed plan's implementation. As noted in the *2014 Long-Term Reliability Assessment*, the BPS is undergoing a fundamental transformation toward increasing dependency on natural gas, wind, and solar resources. The Clean Power Plan substantially accelerates that shift and proposes a very different mix of power resources. NERC's role is to identify emerging reliability issues that must be adequately addressed to ensure future reliability of the electricity supply.

The Clean Power Plan assessment provided a foundation for future reliability analyses and evaluations required by the ERO, stakeholders, and federal and state policy makers to create a framework with timelines that accommodate the expected infrastructure deployments needed to support BPS reliability while achieving the environmental objectives of the proposed rule.

BES Definition and BESnet

FERC approved the revised definition of "BES" on March 20, 2014, as outlined in Order Nos. 743, 773, and 773-A. The definition includes bright-line core criteria with enumerated inclusions and exclusions. The ERO developed enterprise-wide processes and tools to provide a uniform, clear way of determining assets contained within the BES. The tools offer a consistent way to identify assets and manage workflow, which will enhance the reliability of the BPS. The ERO Enterprise-wide software application, the BES Notification and Exceptions Tool, or BESnet, is used by entities to submit notifications of changes to BES assets that affect their responsibilities for compliance with the Reliability Standards.

As a result of the new definition, all elements and facilities necessary for the reliable operation and planning of the BPS will be included as BES Elements. FERC also approved the process for review of elements on a case-by-case basis to enable exceptions from the definition, where appropriate, as well as a process for entities to self-notify Regions of their determinations of BES Elements.

Physical Security of the BES

Physical security was noted as an emerging focus in the *2014 State of Reliability* report. On March 7, 2014, FERC directed NERC to submit a Reliability Standard within 90 days that would require TOs to identify critical facilities, evaluate the potential threats and vulnerabilities of these facilities, and develop and implement security plans on critical facilities such as transmission stations or substations and their associated primary control centers that, if rendered inoperable or damaged, could have a critical impact on the operation of the interconnection through instability, uncontrolled separation, or cascading failures on the BPS. On May 23, 2014, NERC filed with FERC for approval of its proposed Reliability Standard CIP-014-1, and on November 20, 2014, FERC issued its final rule, largely approving this standard.

NERC explained in the filing that the proposed Reliability Standard is just part of its "multi-pronged approach" to ensuring the physical security of the nation's BPS, which includes posting security guidelines and best practices and holding periodic grid security exercises and an annual grid security conference. The new standard also would complement two existing standards:

1. EOP-004-2 requires registered entities to report to NERC and law enforcement any physical damage or threats to a facility, and
2. CIP-006-5 addresses the management of physical access to critical cyber systems.

[20] http://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf.

With FERC approval, the standard requires a TO Risk Assessment under Requirement R1 to be completed no later than September 30, 2015. Thus, as a first step, each TO is required to develop a Risk Assessment for all of the facilities that meet the specified applicability criteria in the standard. The Risk Assessment consists of transmission analyses designed to identify the critical facilities. Further, as required by the standard, an unaffiliated third party will verify the Risk Assessment no later than December 31, 2015. After the Risk Assessment identifying critical stations or substations is verified, the TO will identify potential threats to those facilities and their primary control centers. A physical security plan for the identified facilities will be created and reviewed by an unaffiliated third party with expertise in physical security.

Essential Reliability Services

The changing generation mix, along with the retirement of conventional generation, increasing demand response, and the introduction of distributed resources, can lead to the loss essential reliability services at both the micro and macro levels. NERC, through the Planning and Operating Committees, commissioned the ERS Task Force (ERSTF) in 2014 to define the reliability services and identify the quantity needed and required location of the services to maintain BPS reliability.

The mission of the ERSTF is to provide a roadmap that ensures BPS reliability for the transition to a generation mix with a high penetration of renewables and reduced conventional and synchronous generation. Conventional generation (steam, hydro, and steam turbine technologies) inherently provides essential reliability services needed to reliably operate the BPS. NERC has identified the building blocks of these essential reliability services, which include voltage support, ramping capability, and frequency support. Generators must be able to continuously balance load and demand throughout the BPS to support transmission voltage and frequency response. Wind, solar, and other variable energy resources that are an increasingly greater share of the BPS provide a significantly lower level of essential reliability services than conventional generation.

The ERSTF developed a concept paper[21] to inform regulators and industry of essential reliability services affected by the integration of renewable resources and retirements of baseload generating plants. The ERSTF then developed four subgroups to review and develop a framework for measures for the essential services:

- Load and Resources Balance
- Frequency Support
- Voltage Support
- Policy and Advisory

The ERSTF developed a Measures Framework Report that lists various measures slated to be evaluated by these subgroups. Five measures were endorsed by the Planning and Operating Committees to pilot by gathering data:

- Synchronous Inertial Response at an Interconnection Level
- Synchronous Inertial Response at the Balancing Authority Level
- Initial Frequency Deviation following largest contingency
- Ramping Variability Needs
- System Reactive and Voltage Support

The task force is also evaluating four other measures in parallel with the pilot. All these measures will be part of the overall recommendations to industry and policy makers. The review and analyses of the above-mentioned measures will be concluded at the end of 2015.

[21] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF Concept Paper.pdf

Chapter 3 – Severity Risk Assessment and Availability Data Systems Summary

Overview of SRI Analysis

The SRI has been useful for measuring the performance of the BPS. During 2013, the Performance Analysis Subcommittee (PAS) undertook significant efforts to enhance and modify the SRI; those efforts are included in this report. All SRIs from prior years have been recalculated using the modified method for year-over-year comparisons.

Key conclusions were:

- All of the highest stress days were the result of extreme weather, notably the polar vortex event in the Eastern Interconnection and the significant pacific coast storms in the Western Interconnection.
- The performance on the highest SRI days[22] in 2014 were poorer than those recorded in many of the previous years, but are directly attributable to weather.
- Load-loss events were not the primary driver of a high SRI day during 2014. In fact, all but two of the top-10 days for the year were driven by generator performance and, to a lesser extent, transmission outage performance attributed to weather, and they did not involve load loss.
- There were only three high-stress days (SRI greater than 5.0) in 2014.
- For SRI values less than 5.0, the average was slightly elevated compared with the prior four years; however, the daily variation was less.[23]

NERC Assessment

Figure 3.1 captures the daily SRI values from 2010 to 2014. The SRI is comprised of three key components, notably Generation Severity, Transmission Severity, and Load-Loss Severity. For context throughout this report, each of these severity measures is calculated based on certain assumed and average values as outlined in the SRI white paper[24] and do not rely on individual analyses that measured the specific impact of any given element's function. In particular, Generation Severity reflects the unscheduled generation unavailability of a given unit with a plant capacity as a percentage of all available plant capacity. Transmission Severity reflects the unscheduled unavailability of a particular TADS element event, the impact of which is calculated by a voltage-weighted value divided by the total inventory of TADS elements. Load-Loss Severity is calculated as an average customer usage at peak for the day during which the load-loss event occurred.

As the year-to-year performance is evaluated in Figure 3.1, certain portions of the graph become relevant for specific analysis. First, the left side of the graph, where the system has been substantially stressed, should be considered in the context of the prior years' high-stress days. Next, the slope of the central part of the graph reveals year-to-year changes in performance for the majority of the days of the year and demonstrates routine system resilience. Finally, the right portion of the curve may also provide useful information about how many days with lower SRI occurred during any year compared to other years.

[22] High-stress days are those days in which the BPS performance, as measured by the SRI, has experienced noteworthy impacts to any or all of its components, specifically generation, transmission or load components. Based on past analysis, the count of days that exceed 5 (on the scale of 0 to 1000) are often memorable and may provide lessons learned opportunities. If no days exceed 5, the highest 10 days for the year are generally reviewed for their initiating causes.

[23] For details of the statistical analysis of SRI see Appendix F.

[24] Severity Risk Index, http://www.nerc.com/comm/PC/Performance Analysis Subcommittee PAS 2013/SRI Enhancement Whitepaper.pdf.

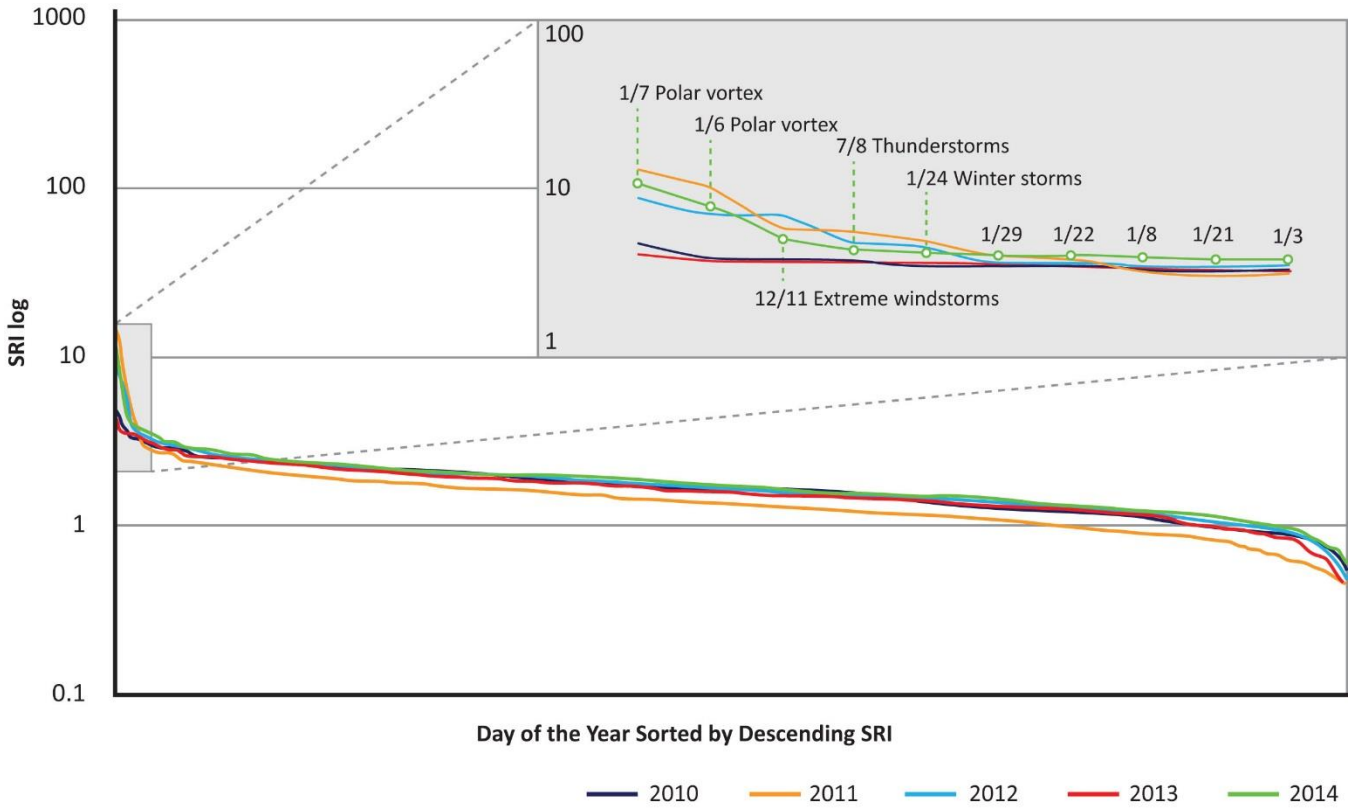


Figure 3.1: NERC Annual Daily Severity Risk Index (SRI) Sorted Descending

The inset shown in Figure 3.1 indicates that in 2014 there were three days for which SRI exceeded 5.0 (viewed as an indicator of a significant day). The first two, January 6 and 7, were associated with the highly discussed polar vortex (as were the eighth and tenth largest SRI days, January 3 and 8); the next one, on December 11, was associated with an extreme weather event in California. Table 3.1 lists the 10 event dates with the highest daily SRI values in 2014 and indicates the component contribution to the SRI. Separately, PAS reviewed OE-417 reports[25] to evaluate the consistency between the load-loss calculation and the OE-417 notification results, and all but one were supported by OE-417 notifications.

[25] https://www.oe.netl.doe.gov/oe417.aspx.

Table 3.1: 2014 Top Ten SRI days

Date	NERC SRI and Weighted Components 2015				G/T/L	Weather Influenced (Verified by OE-417)?	Rank	Event Type	Regions
	SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss					
1/7/2014	11.1	9.8	0.9	0.4		✓	1	Polar Vortex	RF, TRE, SERC
1/6/2014	8.0	6.7	1.2	0.2		✓	2	Polar Vortex	RF, TRE, SERC
12/11/2014	5.0	1.1	0.4	3.6		✓	3	Extreme Windstorm	WECC
7/8/2014	4.2	1.6	0.5	2.0		✓	4	Thunderstorms	RF, NPCC
1/24/2014	4.1	3.1	0.9	0.1		✓	5	Winterstorm	RF, NPCC
1/29/2014	4.0	2.9	0.9	0.2			6	Winterstorm	RF, NPCC
1/22/2014	3.9	3.4	0.4	0.0		✓	7	Winterstorm	RF, NPCC
1/8/2014	3.8	3.4	0.2	0.2		✓	8	Polar Vortex	RF, TRE, SERC
1/21/2014	3.7	3.0	0.5	0.2		✓	9	Winterstorm	RF, NPCC
1/3/2014	3.7	3.4	0.2	0.1		✓	10	Polar Vortex	RF, TRE SERC

Figure 3.2 shows each day's SRI by day of year for 2010 through 2014. On a daily basis, a general normal range of performance exists. Days that were extreme can be detected by their significant deviation from that normal level. It is apparent that these extreme days happen throughout the year, although in 2014 they were heavily weighted within the winter season, as shown in Table 3.1. The top-10 SRI days for the study period are shown in Table 3.2. The Event Rank in Table 3.2 corresponds to the spike numbers in Figure 3.2.

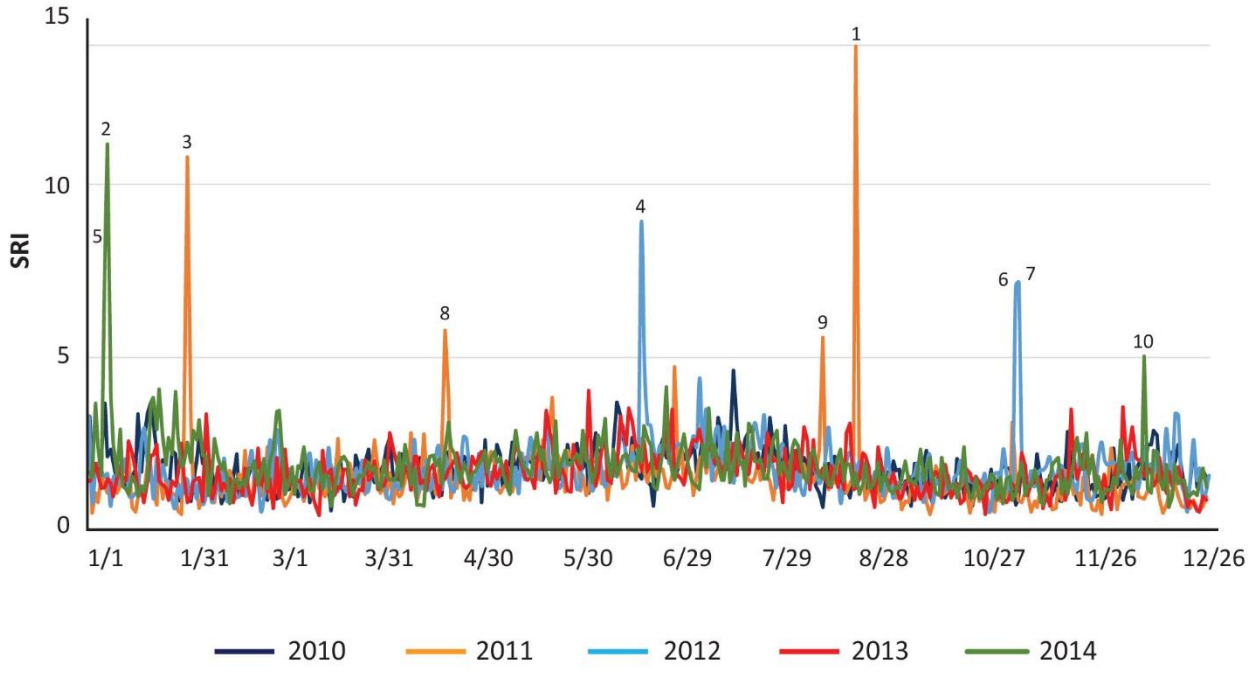


Figure 3.2: NERC Daily SRI (2010–2014)

Table 3.2: Top-10 SRI Days (2010–2014)				
Event Rank as Indicated in chart above	**Date**	**Event Ranking**	**SRI**	**Event Type**
1	9/8/2011	1	14.0	Southwest Blackout
2	1/7/2014	2	11.1	Polar Vortex
3	2/2/2011	3	10.8	Cold Weather Event
4	6/29/2012	4	8.9	Thunderstorm Derecho
5	1/6/2014	5	8.0	Polar Vortex
6	10/30/2012	6	7.2	Hurricane Sandy
7	10/29/2012	7	7.0	Hurricane Sandy
8	4/27/2011	8	5.8	Tornadoes, Severe Storm
9	8/28/2011	9	5.6	Hurricane Irene
10	12/11/2014	10	5.0	Extreme Windstorm

Figure 3.3 shows the annual cumulative performance of the BPS. If a step change occurs on the graph, it represents a stress day as measured by the SRI. Thus, the more gentle and linear the slope of the cumulative curve, the better the performance of the system through the evaluation period. During 2014 it is apparent that the year began worse than any other year, but the balance of the year is somewhat similar to other years.

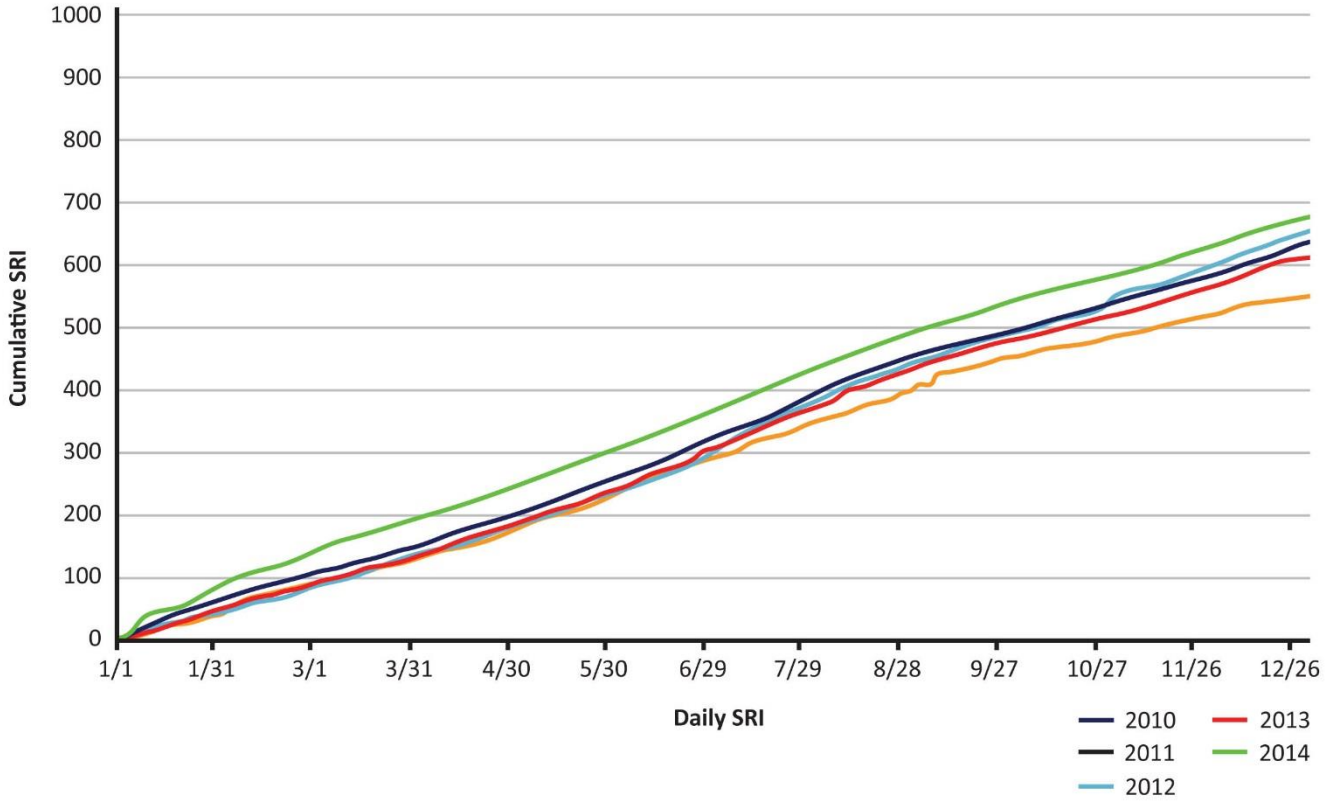


Figure 3.3: BPS Cumulative SRI (2010–2014)

Figure 3.4 breaks down the 2014 cumulative performance by BPS segment. The components are generation, transmission, and load loss, in that order. In Figure 3.4, the load-loss component shows day-to-day load-loss

events but doesn't demonstrate any significant step changes. As noted in previous state of reliability reports, unplanned generation unavailability is the largest contributor to daily SRI. Ongoing GADS analysis[26] will help improve the understanding of how the generation fleet is performing. Additionally, further assessment of the SRI weighting factors should be considered to determine whether modifications to this measure are appropriate. Finally, with the significant role that weather played during 2014, additional studies should be completed to determine the extent of acceptable weather impacts to BPS performance. To the extent that weather is determined as a large impact to day-to-day and extreme-day performance, other metrics that report on load-loss events that retain weather impacts should be developed.

Recommendations

- NERC, through the PAS, should reevaluate SRI criteria to consider weather impacts.
- NERC, through the PAS, should develop metrics that retain weather impacts on load-loss events.

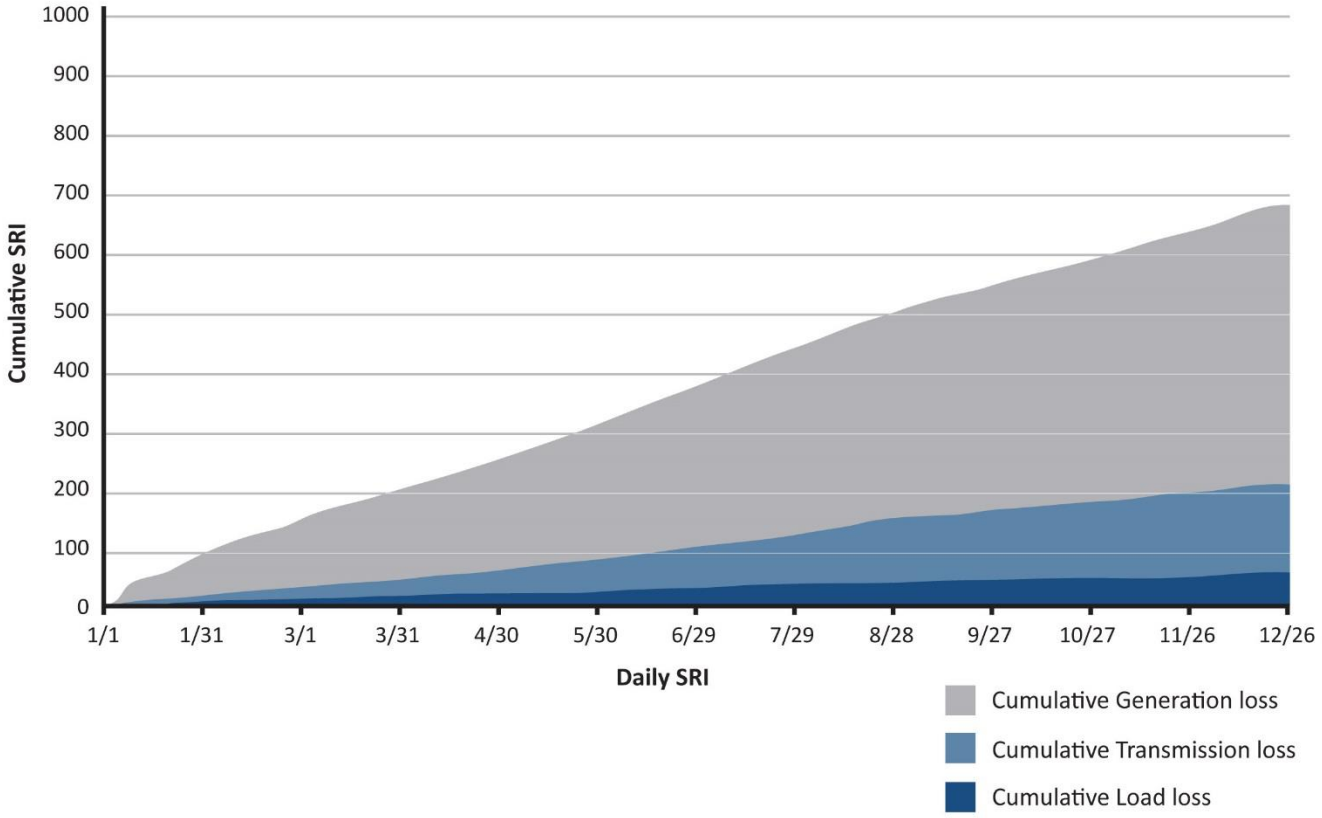


Figure 3.4: NERC Cumulative SRI by Component for 2014

[26] http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

Overview of TADS Data Analysis

A complete analysis of Transmission Availability Data System (TADS) data is presented in Appendix A. First, NERC performed an analysis of all TADS outage events (momentary and sustained). Then NERC limited the study to outage events that resulted in multiple transmission element outages (common or dependent-mode (CDM) events). Next, NERC performed a study on all outage events that lasted for more than a minute (defined as a sustained outage). Finally, NERC studied the transmission outage severity of TADS events by Regional Entity. This year was the first time that NERC performed these studies on sustained outages and Regional Entity variations.

Figure 3.5 represents an analysis of the risk profile of the 2012–2014 TADS events combined study. The x-axis is the magnitude of the correlation of a given Initiating Cause Code (ICC) with transmission outage severity. The y-axis represents the expected transmission outage severity of an event when it occurs. The color of the marker indicates if there is a correlation of transmission outage severity with the given ICC (either positive— Red, negative—Green, or no significant correlation—Blue). The size of the marker indicates the probability of an event initiating in any hour with a given ICC.

The Misoperation ICC (which represents TADS ICCs Failed Protection System Equipment and Human Error associated with Misoperations) and the Failed AC Substation Equipment ICC both show a statistically significant positive correlation with transmission outage severity and show a higher relative transmission risk. Power System Condition, while showing a positive correlation of transmission outage severity, has a lower relative transmission risk, based on the probability of this TADS outage event initiating in any hour and its expected transmission outage severity. On the other end of the risk spectrum, Lightning shows a high relative transmission risk but has no significant correlation with transmission outage severity.

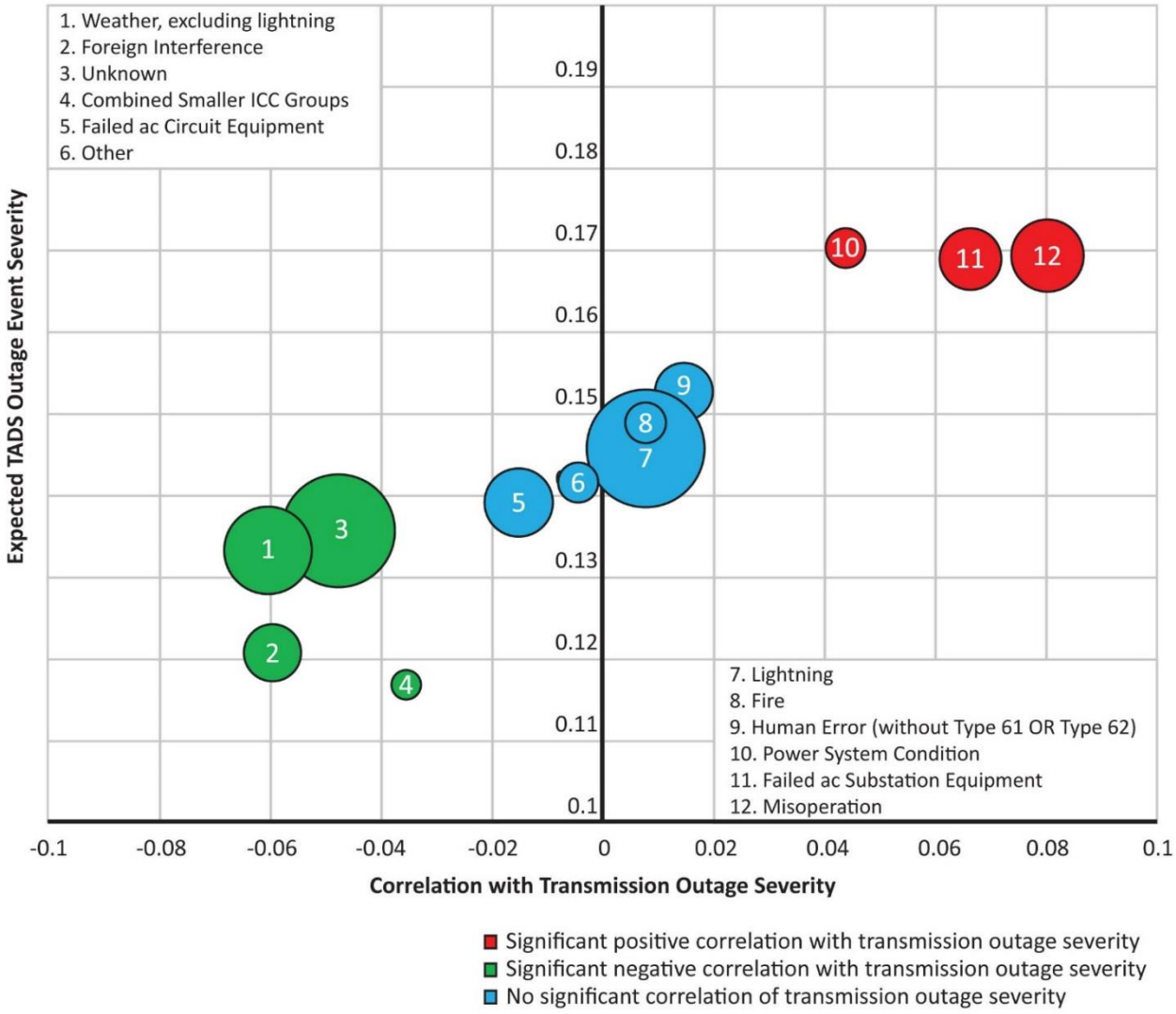


Figure 3.5: Risk Profile of the 2012–2014 TADS Events by ICC

The statistical analysis of the 2012–2014 TADS data on the transmission outage severity and initiating causes of TADS outage events yields the following observations:

- Excluding weather-related and Unknown ICCs, Misoperations and Failed AC Substation Equipment remain the two largest contributors to transmission outage severity risk for all TADS events (momentary and sustained) and all sustained TADS events.
- TADS outage events initiated by either of these ICCs have statistically significant higher expected outage severity than all other TADS outage events.
- Among other ICCs, only Power System Condition has a statistically significant positive correlation with transmission outage severity, but events initiated by this reported cause are less frequent and together contribute only 2.9 percent to the total transmission outage severity of the 2012–2014 TADS events.
- Statistical tests show that the average transmission outage severity of the events initiated by both Misoperations and Failed AC Substation Equipment significantly decreased in 2014 versus 2012.

- Sustained TADS outage events with Unknown ICCs require further review by the TADS Working Group (TADSWG) to determine:
    - The sustained outage events that have an Unknown ICC, and
    - The relative risk of events with both an ICC and sustained cause code of Unknown.
- The ICCs of TADS outage events are very different by Region.

Overview of GADS Data Analysis

A complete analysis of GADS data is presented in Appendix B. An analysis of the age of the existing fleet shows:

- There is an age bubble around 39–47 years, and that population is driven by coal and some gas units.
- There is a significant age bubble around 11–13 years comprised almost exclusively of gas units.

The data set shows a clear shift toward gas-fired unit additions, and the overall age of that fleet across North America is almost 10 years younger than the age of the coal-fired baseload plants that have been the backbone of power supply for many years. This is a trend that is projected to continue given current forecasts around price and availability of natural gas as a power generation fuel.

To understand generator performance, NERC reviewed the top-10 causes of unit outages for the summer and winter seasons, as well as the annual causes, for the 2012–2014 period. The analysis focused on the top causes for non-weather-related outages, measured in terms of lost MWh, so it captures both the amount of capacity during the outage and the duration of the outages. Although only three years of data is available, some observations were made:

- In calendar year 2014, lack of fuel was one of the top-10 causes of generator outages and the second-most frequent cause in winter months. This was the first time that this type of outage placed in the top 10.
- Energy lost during summer has remained relatively consistent over the three-year period.
- Generally, energy lost in the winter season is greater than other periods of the year.
- The energy lost in the 2014 winter showed a significant increase driven in large part by outages related to the polar vortex.
- The sharp increase in the annual value of lost energy reported in 2014 was driven by the winter seasonal outages.

Overview of DADS Data Analysis

A complete analysis of Demand Response Availability Data System (DADS) data is presented in Appendix C. Mandatory collection of detailed demand response data began with the 2011 Summer Period. A review of the summer period data was provided in the *2012 State of Reliability* report. Since 2012, the DADS Working Group (DADSWG) has been working to improve the data quality and process within DADS. Actions taken in the last year include:

- Revising the DADS glossary of definitions,
- Streamlining event type reporting,
- Implementing changes to the webDADS portal, and
- Updating the historically reported event type to align with revised terms.

An analysis of the DADS data for 2014 provides the following observations:

- The registered demand response capacity for all product service types was 44,285 MW for August 2013 and 44,583 MW for 2014, an increase of less than 1 percent.
- Load as a Capacity Resource appears to be the most common use of demand response resources for reliability (66 percent in 2013 and 58 percent in 2014), followed by Direct Control Load Management.
- The impact of the polar vortex is evident in the number of days that demand response was dispatched and the number of affected areas in January 2014.
- Across North America, demand response is used an average of six times a month to respond to reliability events, dispatching an average of 500 MW each month.

Chapter 4 – Reliability Indicator Trends

Reliability Indicator Trends – Summary

NERC Reliability Indicators are intended to tie the performance of the BPS to the set of specified objectives and outcomes for the NERC Reliability Performance Objectives to measure whether an adequate level of reliability (ALR) exists. Based on the events that occurred in 2014 and the metrics data analyzed, the system shows a continuing trend toward sustaining a high level of reliability performance.

One of the stated purposes for the ALR indicators is for the NERC Performance Analysis Subcommittee (PAS) to assess BES reliability and identify gaps in performance and data collection. In 2014, the PAS focused on aligning the existing reliability indicators with the new BES definition.[27] This included evaluating existing metrics to determine those that should continue (with possible modification) and those that should be retired. The PAS also evaluated whether new metrics should be developed.

Table 4.1 shows the mapping of the 14 metrics monitored in 2014 to the seven Reliability Performance Objectives of the ALR definition approved in 2012.[28] In 2013, the PAS introduced a new naming convention (M-x) for the existing 14 metrics shown below. This naming convention was first introduced in the *State of Reliability 2013* report. Both metric naming conventions (M-x and ALRxx) are used in this chapter, but in future reports, the new metric names will be used.

Table 4.1 Adequate Level of Reliability Metrics

Reliability Performance Objectives	System Stability	System Frequency	System Voltage	Manage Contingencies	Coordinate Restoration	Transmission Adequacy	Resource Adequacy
New ID (ALR Metrics)	M-2 (ALR1-4) M-4 (ALR1-12) M-9 (ALR4-1)	M-4 (ALR1-12) M-6 (ALR2-4)		M-2 (ALR1-4) M-6 (ALR2-4) M-7 (ALR2-5) M-8 (ALR3-5) M-11 (ALR6-2)	M-2 (ALR1-4) M-11(ALR6-2)	M-2 (ALR1-4) M-8 (ALR3-5) M-10 (ALR6-1) M-12(ALR6-11) M-13(ALR6-12) M-14(ALR6-13) M-15(ALR6-14) M-16(ALR6-15)	M-1 (ALR1-3) M-11(ALR6-2)

These metrics exist within a reliability framework. The current 14 performance metrics align with the performance objectives for the design, planning, and operation of the BES. These metrics contribute to the Reliability Performance Objectives, which will lead to a more resilient and reliable BES. There is at least one existing performance metric associated with each of the performance objectives listed in the table, except system voltage. The existing metric for system voltage performance M-3 (ALR 1-5) was retired in 2014. Efforts are underway to develop one or more metrics to more effectively determine system voltage performance.

The definition of ALR speaks to the state of the BES in which the Performance Objectives are met. It is therefore intuitive that one could not base such an assessment of reliability on one metric only. Rather, it is necessary to look at the entire set of metrics to evaluate that the ALR state has been attained. Any comparisons of individual metrics alone or between Regions, or to value one metric higher than another, should be evaluated with care.

[27] http://www.nerc.com/pa/Stand/Pages/Project2010-17_BES.aspx.

[28] Definition of "Adequate Level of Reliability," http://www.nerc.com/comm/Other/Adequate_Level_of_Reliability_Task_Force_ALRTF_DL/Final_Documents_Posted_for_Stakeholders and Board of Trustee Review/10_04_12_ALR_Definition_clean.pdf (The last two performance objectives relate to planning assessments, which are not covered in the report).

Another metric reporting principle is to retain anonymity of individual reporting organizations. Thus, details are presented in this report at a NERC level, and a Regional Entity level, and do not compromise anonymity of individual reporting organizations.

Process Overview

Building upon previous metric reviews, the results of the approved performance metrics continue to be assessed. Each metric is designed to provide a measure of one or more Reliability Performance Objectives. Due to varying data availability, each of the performance metrics does not address the same time period (some metrics have just been established or modified, while others represent data collected over many years). At this time, the number of metrics is expected to remain relatively stable; however, the PAS annually reviews the set of metrics and, working with industry subject matter experts, may recommend changes to metrics, or new metrics, as gaps are identified in reliability data needed to assess the state of reliability of the BES.

In 2014, The PAS performed this review, which resulted in the retirement of metrics ALR1-5 and ALR2-3 and the modification of several others. Specific changes to metrics that were approved in 2014 and those that are ongoing will be described in greater detail in this section.

Table 4.2 provides an overview of the ALR metric trends through 2014. Although a number of performance categories have been assessed, some do not yet have sufficient data to derive conclusions from the metric results. Assessment of these metrics should continue as additional data becomes available to determine if the metric is a good indicator of the performance objective it is meant to measure. As indicated below, most of the ALR metrics have been revised in the past two years.

Trend Rating Symbols	
Significant Improvement	●
Slight Improvement	◕
No Change	◑
Inconclusive/Mixed	◑*
Slight Deterioration	◔
Significant Deterioration	○
New Data	◑***
Incomplete dataset/not enough to draw any conclusion	◑**
Retired	N/A

Table 4.2: Metric Trends		
Metric	**Description**	**Trend Rating**
M-2 (ALR1-4)	BPS Transmission-Related Events Resulting in Loss of Load (modified in early 2014)	●
M-3 (ALR1-5)	System Voltage Performance (discontinued in 2014)	N/A
M-4 (ALR1-12)	Interconnection Frequency Response	◑*
M-5 (ALR2-3)	Activation of Underfrequency Load Shedding (discontinued in 2014)	N/A
M-6 (ALR2-4)	Average Percent Non-Recovery Disturbance Control Standard Events	◑*
M-7 (ALR2-5)	Disturbance Control Events Greater than Most Severe Single Contingency	◑
M-8 (ALR3-5)	Interconnected Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances (modified in 2013)	◑*
M-9 (ALR4-1)	Correct Protection System Operations	◑
M-10 (ALR6-1)	Transmission Constraint Mitigation	◑**
M-11(ALR6-2)	Energy Emergency Alerts (modified in 2013)	◕
M-12 (ALR6-11)	Automatic AC Transmission Outages Initiated by Failed Protection System Equipment (modified in late 2014)	◑**
M-13 (ALR6-12)	Automatic AC Transmission Outages Initiated by Human Error (modified in late 2014)	◑**
M-14 (ALR6-13)	Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment (modified in late 2014)	◑**
M-15 (ALR6-14)	Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment (modified in late 2014)	◑**
M-16 (ALR6-15)	Element Availability Percentage (APC) and Unavailability Percentage (modified in 2013)	◑**

The following provides a discussion of each metric and activity on certain metrics where changes have been implemented and those that are associated with key findings. The full set of metrics and their descriptions, along with the results and trending, are on the NERC public website.[29]

M-2 (ALR1-4) BPS Transmission-Related Events Resulting in Loss of Load

Background

This metric measures BPS transmission-related events resulting in the loss of load, excluding weather-related outages. Planners and operators can use this metric to validate their design and operating criteria by identifying the number of instances when loss of load occurs. For the purposes of this metric and consistent with the revised metric approved by the Operating and Planning Committees in March, 2014, an "event" is an unplanned disturbance that produces an abnormal system condition due to equipment failures/system operational actions (either intentional or unintentional) that result in the loss of firm system demands, utilizing the subset of data provided in accordance with EOP-004-2. The reporting criteria for such events beginning with data for events occurring in 2013 are outlined below:[30]

1. Loss of firm load for 15 minutes or more:
   a. 300 MW or more for entities with previous year's demand of 3,000 MW or more.
   b. 200 MW or more for all other entities.

[29] Assessments & Trends: Reliability Indicator, http://www.nerc.com/pa/RAPA/Pages/ReliabilityIndicators.aspx.
[30] http://www.nerc.com/pa/rrm/ea/EA Program Document Library/Final_ERO_EA_Process_V2.1.pdf.

2. BES Emergency requiring manual firm load shedding of 100 MW or more.
3. BES Emergency resulting in automatic firm load shedding of 100 MW or more (via automatic under voltage or under frequency load shedding schemes, or SPS/RAS).
4. Transmission loss event with an unexpected loss within an entity's area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing) resulting in a firm load loss of 50 MW or more.

This metric was reviewed by the PAS in 2013, and changes were made to make the criteria consistent with the approved changes to EOP-004-2 reporting criteria pertaining to transmission-related events that result in loss of load. The criteria presented above were approved for implementation in the first quarter of 2014. Changes in the annual measurement between 2012 and 2013 therefore reflect the addition of criterion 4, which has been applied to the 2013 and 2014 data. For the first part of the analysis below, historical data back to 2002 was used, and the new criterion 4 was not included, to enable trending of the other aspects of the metric over time. Figure 4.3 includes all of the criteria; therefore, it was only evaluated for 2013 and 2014, the time period for which data collection associated with the new criterion was available.

Assessment

Figure 4.1 shows the number of BPS transmission-related events resulting in loss of firm load from 2002 to 2014. Figure 4.2 provides a breakdown of the events per year by load interrupted. In 2014, there were fewer events than any other year in the data set except for 2012. The year 2014 has the second-lowest average level of load lost in megawatts of all years for which data exists, with three events resulting in 1160 MW of load lost.

With three years of data indicating that the number and megawatt load loss amount for the past three years is significantly less than previous years, M-2 has shown marked improvement over the assessment period.

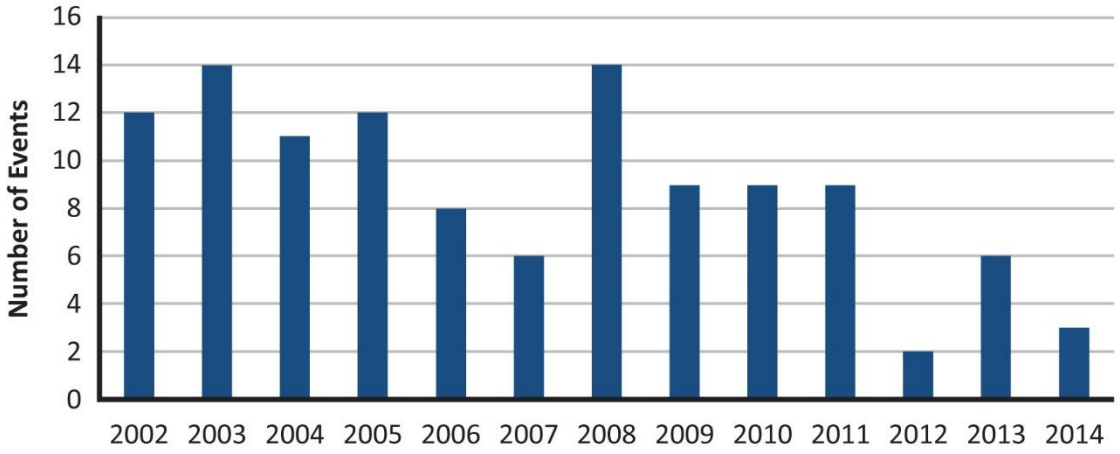
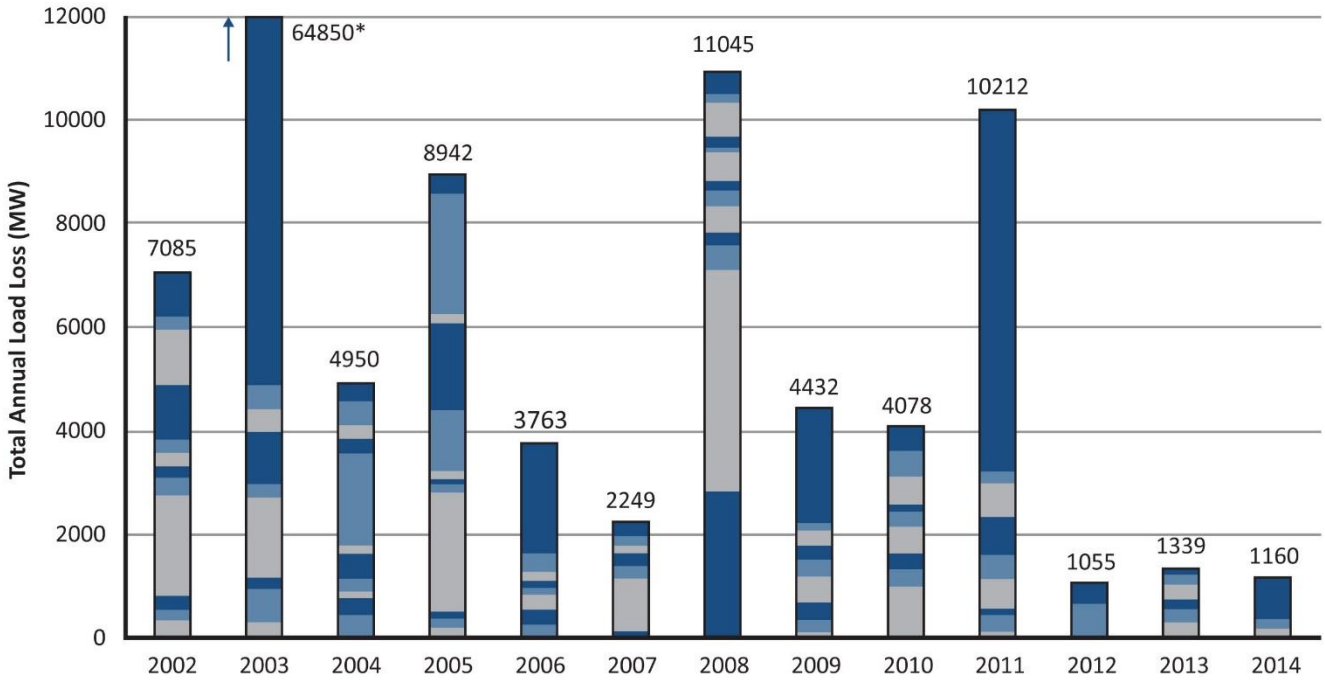


Figure 4.1: M-2 (ALR1-4) BPS Transmission-Related Events Resulting in Load Loss (2002–2014 – Excluding Criteria 4)



Each band of color represents a different event.

**Vertical axis scale has been reduced due to large value of 2003 NE blackout event.*

Figure 4.2: M-2 (ALR1-4) BPS Transmission-Related Events Resulting in Load Loss (Excluding Criteria 4)

Table 4.3 shows total megawatt loss values and duration of events resulting in firm load loss of 50 MW or greater and includes all four criteria for this metric. This table shows that in 2014, in addition to the three events that were reported and shown in Figures 4.1 and 4.2 under criteria 1, 2, and 3, there were three additional events that were associated with the new criterion. While Figures 4.1 and 4.2 show 2014 transmission-related load-loss events based on the historical metric language, Table 4.3 shows what the number and load loss would be for transmission-related load loss events in 2013 and 2014. Further analysis and continued assessment of the trends over time will continue.

Table 4.3: 2013 and 2014 Events with Load Loss ≥ 50 MW (Including Criteria 4)

Duration (hours)	2013	2014
3.83	300	
2.73	240	
10.33	200	
1.5	297	
1.63	200	
1.25	102	
3.03	51	
3.82	90	
7.27	90	
2.82	70	
1.3	50	
3		797
1.7		200
1.67		163
0.83		95
0.97		71
1.02		63

Special Considerations

The collected data does not indicate whether load loss during an event occurred as designed. Data collection will be refined in the future for this metric to allow enable data grouping into categories, such as separating load loss as designed from unexpected firm load loss. Also, differentiating between load loss as a direct consequence of an outage compared to load loss as a result of an operator-controlled action to mitigate an IROL/SOL exceedance should be considered.

M-3 (ALR1-5) System Voltage Performance

Background

This metric was removed from the monitored set in 2014 and will no longer be included in future reports.

Data collection consisted of the total number of key buses/nodes being monitored at 345 kV and above, the total number of minutes by quarter that the voltage was either above the predetermined upper threshold or below the predetermined lower threshold. With more than two years of data collected and reviewed, the PAS determined that there was insufficient information about voltage performance in the collected data for the M-3 metric and data collection has been discontinued.

Future Development

In 2014, NERC established the Essential Reliability Services Task Force (ERSTF), a team tasked with identifying those Essential Reliability Services that are the elemental reliability building blocks necessary to maintain BPS reliability and associated measures. The ERSTF has recommended a measure[31] that was approved by the Operating Committee (OC) and Planning Committee (PC) for data collection and testing, which may support development of new voltage and reactive support metrics going forward.

M-4 (ALR1-12) Interconnection Frequency Response

Background

The purpose of this metric is to monitor interconnection frequency response, which is a measure of an interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load. It is a critical component to the reliable operation of the BPS, particularly during disturbances. The metric measures the average frequency response for all events where frequency deviates more than the interconnection's defined threshold.

The following are frequency response calculations of the Eastern, Western, ERCOT, and Québec Interconnections. Figure 4.3 shows the criteria for calculating average values A and B used to report frequency response. The event starts at time t±0. Value A is the average from t-16 to t-2 seconds, and Value B is the average from t+20 to t+52 seconds. The difference of value A and B is the change in frequency[32] used for calculating frequency response. The monthly frequency event candidate lists are posted on the NERC Resources Subcommittee[33] website. These lists are vetted by the NERC Frequency Working Group and the final list is published on a quarterly basis. The data is used to support Reliability Standard BAL-003-1. The frequency event data collection process is described in the BAL-003-1 Frequency Response Standard Supporting Document.[34]

[31] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF - Framework for Measures Report January 2015 - Final.pdf.

[32] ALR1-12 Frequency Response Data Collections Process, Slide 18 of Presentation 1, 10/26-27/2011 http://www.nerc.com/docs/oc/rs/RS_Presentation_October_2011.pdf.

[33] Resource Subcommittee (RS), http://www.nerc.com/comm/OC/Pages/Resources-Subcommittee-(RS)-2013.aspx.

[34] BAL-003-1 Frequency Response & Frequency Bias Setting Standard, 07/18/2011, http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/NOPR_Proposal for BAL-003-1.pdf.

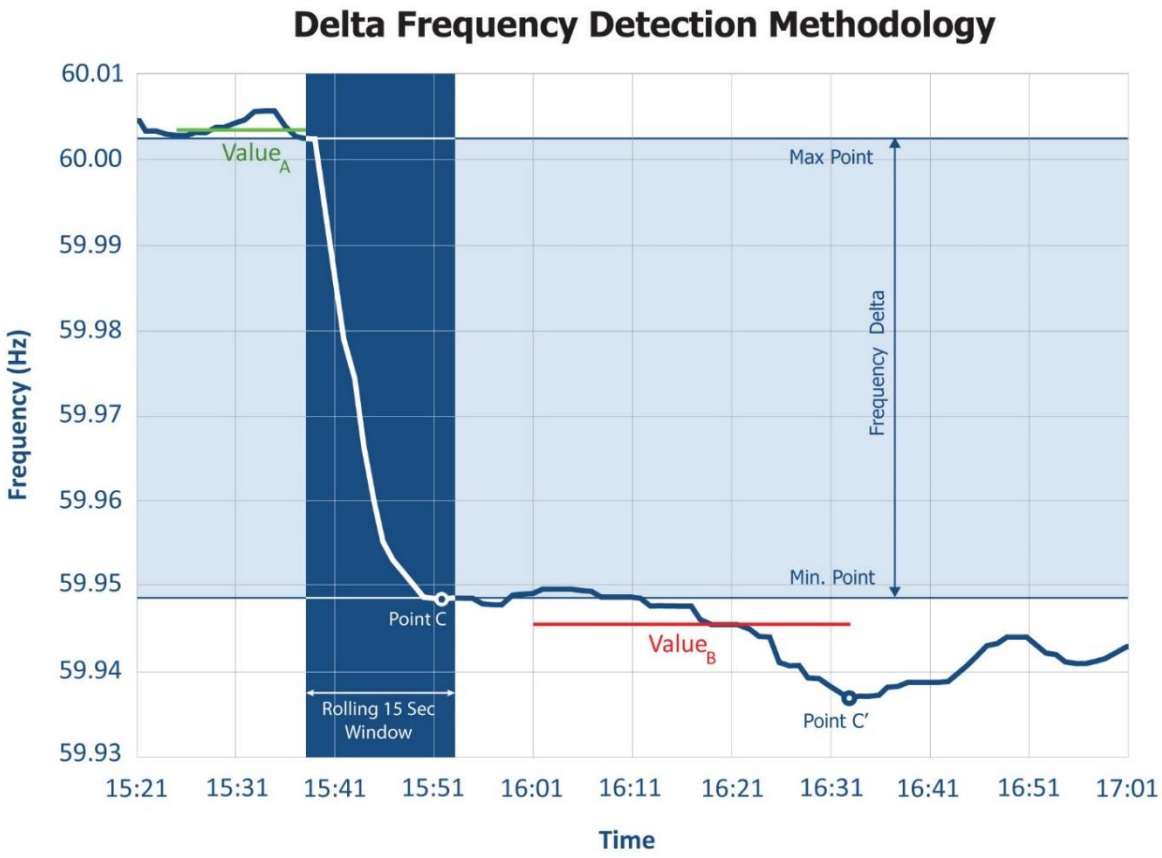


Figure 4.3: Criteria for Calculating Value A and Value B

The actual megawatt loss from a generation frequency event is determined jointly by NERC and Regional Entity situation awareness staff to develop the monthly frequency event candidate list. Both the change in frequency and the megawatt loss determine whether the event qualifies for further consideration for use in the M-4 metric or for the measurement of BA performance under Reliability Standard BAL-003-1 by the NERC Frequency Working Group. If the event qualifies, then the actual MW loss is converted to a beta value (MW/.1 Hz) for use in Figure 4.3 above. The final monthly datasets of approved frequency events[35] are then used to analyze the interconnection frequency response performance.

In examining the frequency event selection process, NERC staff found that process to be too restrictive in event selection. The Resources Subcommittee and NERC staff have made recommendations to improve the process for selecting frequency events.[36]

[35] Starting in 2014, all frequency events selected for use in BAL-003 shall be also used for the ALR 1-12 frequency performance metric.
[36] http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf

Table 4.4 shows a proposed set of revisions to the event detection and selection triggers for M-4.

Table 4.4: ALR 1-12 Frequency Event Candidate Triggers

Interconnection	Detection		Selection	
	MW Load Loss[37]	MW Resource Loss	MW Load Loss[34]	MW Resource Loss
Eastern	800	750	800	800
Western	700	650	700	700
ERCOT	450	400	450	450
Québec	450	400	450	450

The recommended criteria for frequency events also include the following:

- All BAL-003-1 frequency events should be a subset of the ALR 1-12 event set.
- All event detection windows are to remain at 15-second rolling windows.
- No change is recommended to the BAL-003-1 event selection process.
- Actual net megawatt loss will be verified for each megawatt loss event. Megawatt changes for load loss or pumped storage load rejection events will rely on FNet[38] estimates until better data sources become available.
- Data for all candidate events will be collected from the FNet system (Values A and B, Point C, Point C', and 300 seconds of high-speed frequency data surrounding the event). These data will be stored in a database for use in the annual analysis.
- Events could be triggered from several sources:
  - The FNet system alarms
  - Reliability Coordination Information System (RCIS) messages
  - E-mail
  - Telephone calls
- Screen only actual megawatt change against the megawatt criteria.
- No criteria will be applied on frequency change parameters, allowing for purer statistical analysis of interconnection performance.
- Weekly reviews will be conducted by NERC staff to screen candidate events for ALR 1-12 selection.
- Investigate the potential for applying a T=+0 to Point C slope (arresting slope) criteria to eliminate shallow slopes that may not be reflective of primary frequency response.

Data errors were determined to have existed in the 2013 data set; however, this did not alter the findings of the report. It changed one slightly negative trend to a positive one and resulted in key information being

[37] Or Pumped-Storage Load Rejection.

[38] Operated by the Power Information Technology Laboratory at the University of Tennessee, FNet is a low-cost, quickly deployable GPS-synchronized wide-area frequency measurement network. High dynamic accuracy Frequency Disturbance Recorders (FDRs) are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNet servers hosted at the University of Tennessee and Virginia Tech.

identified for the industry. The following summarizes the findings of NERC staff in their analysis of frequency response performance and the modifications to 2013 data:[39]

- Frequency event selection errors during 2013 were found in the ALR 1-12 Frequency Response metric that were presented in the *State of Reliability 2014* report. This resulted in 19 Eastern Interconnection events being eliminated from the set of ALR 1-12 events. This resulted in a change from the slightly negative trend reported in the *State of Reliability 2014* report to a statistically significant positive trend. The analysis for the Eastern Interconnection is corrected in this report, and that correction has been made to the NERC Reliability Indicators dashboard.[40]
- Frequency step-change[41] anomalies were found in the 2013 1-second Eastern Interconnection frequency data used to determine the starting frequency for the IFRO calculations. The problem was traced back to toggling back and forth between two data sources in the calculation of the 1-second averaged data. The entire 2013 1-second database was recalculated to correct the anomalies.
- An error was discovered in several start times for frequency events in the Eastern, Western, ERCOT, and Québec Interconnections starting in July 2013.[42] The problem arose from a sign error in an adjustment factor used to remove a time skew inherent in the high-speed metrology; instead of removing the time skew, the adjustment factor was doubling it. This impacted several of the adjustment factors used in the IFRO calculation related to Point C. The error was corrected and all timing of frequency events have been recalculated for this and future analyses.

Table 4.5 shows the number of frequency events per year for each interconnection from 2012 through 2014. This represents a change in the frequency response data provided in the 2013 and 2014 *State of Reliability* reports. The trend results and statistical analysis provided in this section and in Appendix D include the updated set of frequency events.

Table 4.5: Annual Number of Frequency Events

Interconnection	2012	2013	2014
Eastern	16	36	45
ERCOT	53	48	37
Quebec	21	29	24
Western	10	23	35

The new threshold, which is 36 mHz below 59.960 Hz (Point C in Figure 4.3) and delta Hz more than 30 mHz within a 15-second time window, resulted in an increase in the number of events for the Eastern Interconnection in 2013. Care must be taken to select events that impact frequency beyond the expected deadband settings for each Interconnection. Beta megawatt projections for events that are slightly larger than the Interconnection megawatt cutoff threshold can potentially result in outliers. The resulting frequency response for these smaller events may be small if generator governors have dead bands set higher than the expected value. Another factor that can impact the projected beta megawatt value is the 32-second average value chosen for point B. If the frequency response is not sustained for the duration of the 32-second average, the resulting frequency response will be lower and consequently result in a lower beta megawatt value. Lack of sustained frequency response is evident in the Eastern Interconnection and is referred to as the "Lazy L" in frequency over time charts.

[39] http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf.

[40] Located at: http://www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx.

[41] Abrupt changes in frequency.

[42] This problem did not affect the 2013 IFRO calculations because it began after the time frame used in those calculations.

On February 5, 2015, NERC issued an Industry Advisory on generator governor frequency response.[43] NERC determined that a significant portion of the Eastern Interconnection generator dead bands or governor control settings inhibit or prevent frequency response. With the exception of nuclear generators, entities with generators greater than 75 MVA were advised to review generator governor and Distributed Control System (DCS) settings to conform to specifications mentioned in the Advisory.

Assessment

NERC annually applies statistical tests to interconnection frequency response datasets,[44] and additional analyses on time of year, load levels, and other attributes have been conducted annually since 2013. Frequency response is the absolute value of the ratio of the megawatts lost when generation is tripped and the difference in frequency before and after the event. A large value of frequency response is considered better than a small value.

Frequency Response Trending

From 2012 through 2014, the historical frequency response shows the following trends:

- Frequency response performance in ERCOT and the Western Interconnection was stable, with a time trend being statistically flat.
- Frequency response in the Eastern Interconnection has shown a statistically significant improvement with the average monthly rate of increase of 15.0 MW/0.1 Hz.
- The Québec Interconnection experienced a statistically significant decline with the average monthly rate of decrease of 6.8 MW/0.1 Hz.

The differences in the evaluations of the frequency response performance compared with the *State of Reliability 2014* report are due to the addition of the 2014 data, and also to a removal of the 2009–2011 data (based on new selection criteria) and a major revision of the 2012–2013 data as described above. Still, the current three-year datasets are relatively small, and a future addition of annual frequency response values might change the trends.

Statistical Significance Test Results

Statistical significance tests were applied to Interconnection frequency response datasets, and additional analysis on time of year, load levels, and other attributes were also conducted. Following are the overall observations and test results:

- The Eastern Interconnection frequency response has shown a statistically significant increase from 2012 to 2014, with an average monthly rate of increase of 15.0 MW/0.1 Hz.[45]
- The ERCOT Interconnection frequency response was stable from 2012 to2014, with a statistically flat time trend.[46]

[43] http://www.nerc.com/pa/rrm/bpsa/Alerts DL/2015 Alerts/NERC Alert A-2015-02-05-01 Generator Governor Frequency Response.pdf.

[44] Datasets described in the Frequency Response Initiative Report, October 2012 http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf.

[45] The correlation between time variable and frequency response is positive ,and this is equivalent to the fact that the slope is positive and the trend line is increasing function with the average monthly growth of 15.0 MW/Hz*0.1; moreover, the correlation is statistically significant (p=0.03). This leads to the rejection of the null hypothesis of zero correlation. So, the observed increasing trend for frequency response unlikely occurred by chance.

[46] The correlation between time variable and frequency response is positive and this is equivalent to the fact that the slope is e and the trend line is increasing function. However, the correlation is not statistically significant. This leads to the failure to reject the null hypothesis of zero correlation. So even though the increasing trend for frequency response in time was observed, there is a high probability that the positive correlation and the positive slope occurred by chance.

- The Québec Interconnection frequency response experienced a statistically significant decline in 2012–2014, with an average monthly rate of decrease of 6.8 MW/0.1 Hz.[47]
- The Western Interconnection frequency response was stable from 2012 to –2014, with a statistically flat time trend.[48]

The statistical analysis of the observed trends can be found in Appendix D.

[47] The correlation between time variable and frequency response is negative, and this is equivalent to the fact that the slope is negative and the trend line is a decreasing function with the average monthly decrease of 6.8 MW/Hz*0.1; moreover, the correlation is statistically significant (p=0.007). This leads to the rejection of the null hypothesis of zero correlation. So, the observed decreasing trend for frequency response unlikely occurred by chance.

[48] The correlation between time variable and frequency response is negative and this is equivalent to the fact that the slope is negative and the trend line is decreasing function. However, the correlation is not statistically significant. This leads to the failure to reject the null hypothesis of zero correlation. So even though the decreasing trend for frequency response in time was observed, there is a high probability that the negative correlation and the negative slope occurred by chance.

Eastern Interconnection

Figure 4.4 is a scatter plot of the frequency response of reviewed events in the Eastern Interconnection for 2012 to 2014. The time trend line had a statistically significant positive slope, which demonstrates that frequency response is improving over time in the Eastern Interconnection. The IFRO is shown as well, and none of the frequency response values fell below the IFRO. The sample statistics by year are listed in Table 4.6. The last column lists the number of frequency response events that fell below the absolute IFRO.[49]

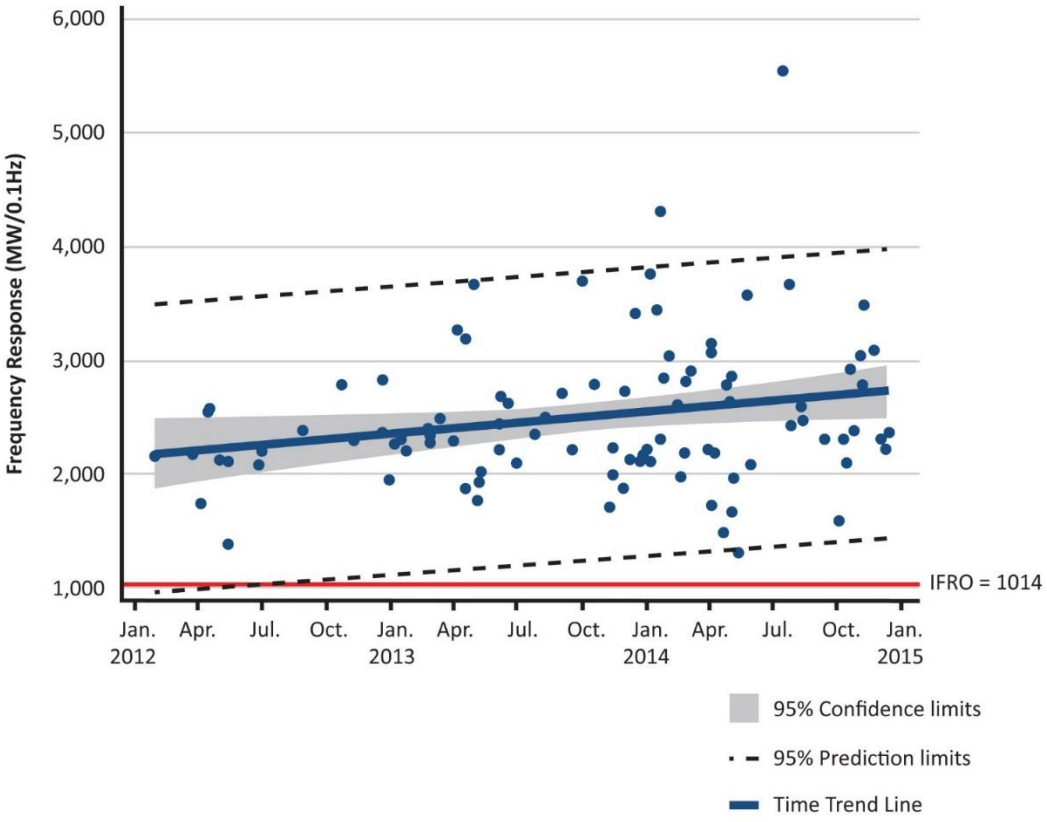


Figure 4.4: Eastern Interconnection Frequency Response Trend 2012–2014

Table 4.6: Sample Statistics for Eastern Interconnection

Year	Number of Values	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO of 1014 MW/0.1 Hz
2012-2014	**97**	**2488.28**	**642.43**	**2307.43**	**1300.26**	**5552.36**	**0**
2012	16	2229.13	368.22	2187.47	1374.02	2824.55	0
2013	36	2415.84	500.78	2282.03	1707.03	3696.28	0
2014	45	2638.38	776.53	2469.33	1300.26	5552.36	0

[49] http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf.

Western Interconnection

Figure 4.5 is a scatter plot of the frequency response of reviewed events in the Western Interconnection from 2012 to 2014. The time trend line had a nonsignificant negative slope, which demonstrates that frequency response has been stable from 2012 through 2014 in the Western Interconnection. The sample statistics by year are listed in Table 4.7. The last column lists the number of frequency response events that fell below the absolute IFRO.[50] In 2012–2014, there were four occurrences of frequency response events with values below the IFRO, which is 907 MW/0.1 Hz.

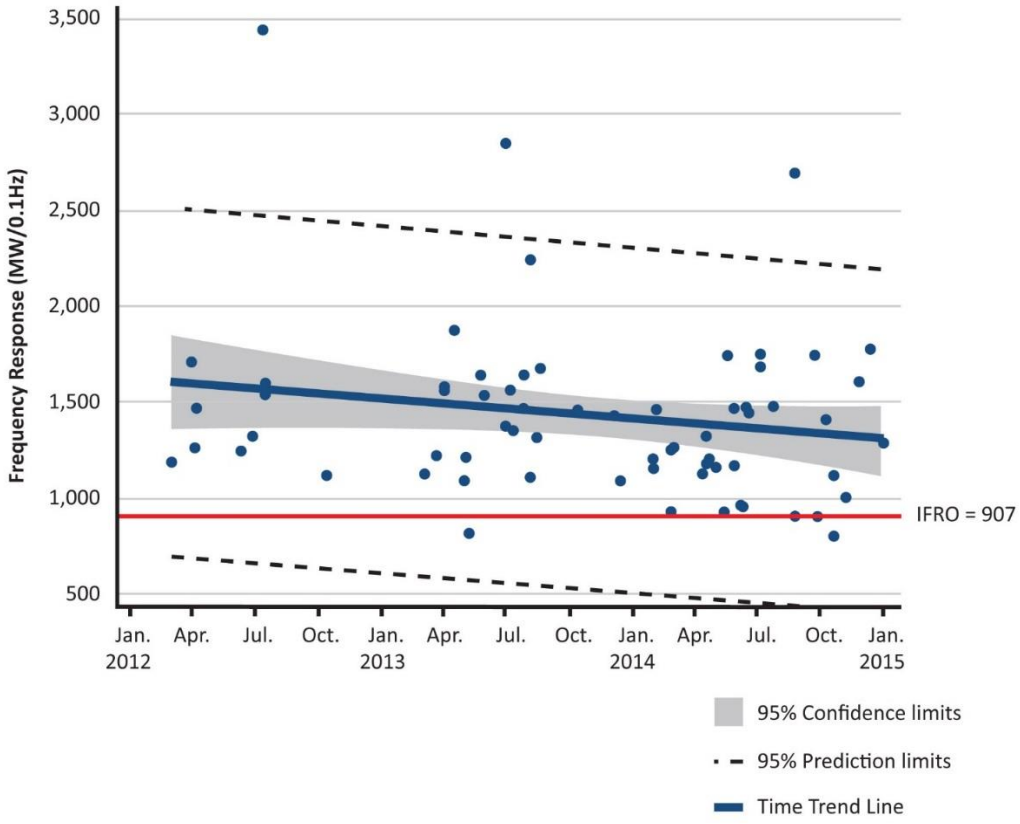


Figure 4.5: Western Interconnection Frequency Response Trend 2012–2014

Table 4.7: Sample Statistics for Western Interconnection

Year	Number of Values	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO of 907 MW/0.1 Hz
2012-2014	**68**	**1419.06**	**444.92**	**1336.80**	**798.34**	**3439.70**	**4**
2012	10	1590.47	677.49	1396.43	1120.51	3439.70	0
2013	23	1489.99	421.93	1463.11	821.85	2850.99	1
2014	35	1323.47	363.24	1265.64	798.34	2695.58	3

[50] http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf

ERCOT Interconnection

Figure 4.6 is a scatter plot of the frequency response of reviewed events in the ERCOT Interconnection from 2012 to 2014. The time trend line had a nonsignificant positive slope, which demonstrates that frequency response has been stable from 2012 through 2014 in the ERCOT Interconnection. The sample statistics by year are listed in Table 4.8. The last column lists the number of frequency response events that fell below the absolute IFRO.[51] In 2012–2014 there were 21 occurrences of frequency response events with values below the IFRO, which is 471 MW/0.1 Hz.

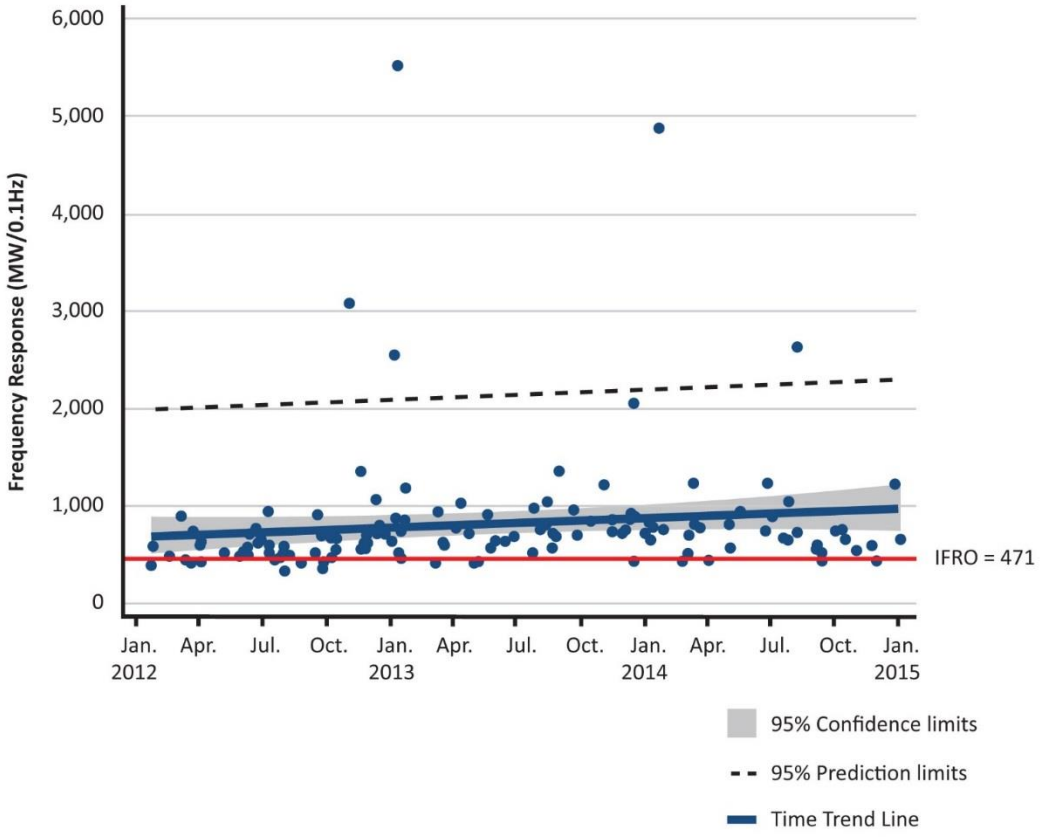


Figure 4.6: ERCOT Frequency Response Trend 2012–2014

Table 4.8: Sample Statistics for ERCOT Interconnection

Year	Number of Values	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO of 471 MW/0.1 Hz
2012-2014	**138**	**809.70**	**661.67**	**663.83**	**336.77**	**5530.50**	**21**
2012	53	650.58	386.28	577.88	336.77	3082.64	12
2013	48	921.60	777.52	745.51	406.60	5530.50	5
2014	37	892.45	774.79	725.26	425.66	4879.72	4

[51] http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf

Québec Interconnection

Figure 4.7 is a scatter plot of the frequency response of reviewed events in the Québec Interconnection for 2012–2014. The time trend line had a statistically significant negative slope, which demonstrates that frequency response is decreasing over time in the Québec Interconnection. The sample statistics by year are listed in Table 4.9. The last column lists the number of frequency response events that fell below the absolute IFRO.[52]

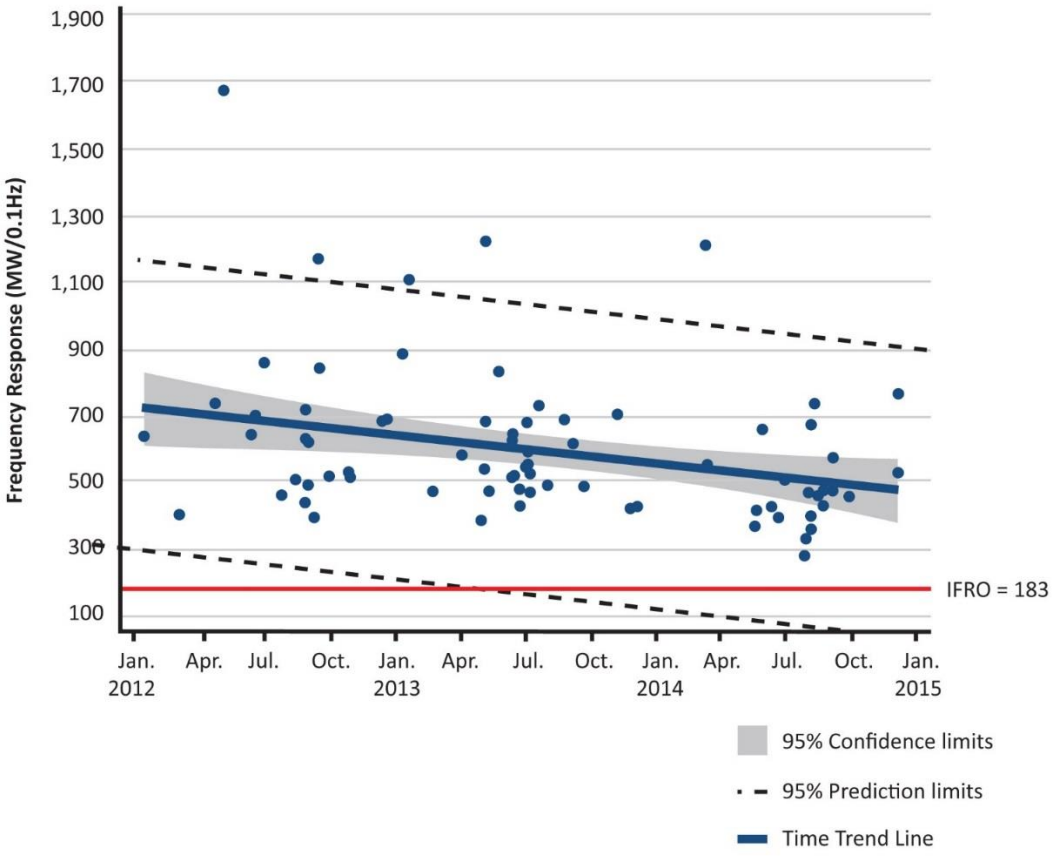


Figure 4.7: Québec Interconnection Frequency Response Trend 2012–2014

Table 4.9: Sample Statistics for Quebec Interconnection

Year	Number of Values	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO of 183 MW/0.1 Hz
2012-2014	**74**	**591.8**	**220.6**	**526.9**	**288.3**	**1673.6**	**0**
2012	21	656.2	268.0	635.0	397.2	1673.6	0
2013	29	606.5	192.2	545.9	389.1	1227.8	0
2014	24	517.7	192.8	465.1	288.3	1212.4	0

[52] http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf.

Relation to Interconnection Frequency Response Obligations

The expected frequency response for each interconnection was compared to their respective IFROs from the *2014 Frequency Response Annual Analysis*. In all cases, the statistically expected frequency response for each interconnection has been greater than the recommended absolute IFRO values.[53]

The historical frequency responses show the following:

- There were no events during the assessment period for which the frequency response of the Eastern Interconnection or the Québec Interconnection was below the IFRO.
- The Western Interconnection had four events with frequency response values below the absolute IFRO, which amounts to 6 percent of all Western Interconnection events for the three years. Three of the events occurred in 2014.
- The ERCOT Interconnection had 21 events with frequency response values below the absolute IFRO, or 15 percent of all events for the three years. Four of these events occurred in 2014, showing an improvement in frequency performance over time.

Recommendations from NERC Staff and the Resource Subcommittee for M-4 (ALR 1-12) Frequency Event Detection and Selection Process Changes

In the annual review of frequency response, NERC staff identified several concerns. The recommendations outlined in the *2014 Frequency Response Annual Analysis* were incorporated into the data collection process for this report and include the following:

- Monthly processing of 1-second data and weekly review of frequency event candidates for both M-4 (ALR 1-12) and BAL-003-1 are recommended to discover problems earlier and ensure consistency in event selection.
- The Resources Subcommittee and NERC staff recommend that the process for selecting M-4 events be carefully reviewed and analyzed prior to the publication of the *State of Reliability 2015* report.
- The selection process discounted events that started above 60 Hz that did not fall below certain frequency deviation thresholds. This tends to corrupt any analysis of the statistical relationship between frequency response performance and starting frequency or ending frequency, and potentially eliminates events of high frequency response performance for large events or low frequency response for large megawatt changes in an Interconnection.

M-5 (ALR2-3) Under Frequency Load Shedding

Background

This metric was removed from the monitored set in 2014 and will no longer be included in future reports. The purpose of Under Frequency Load Shedding (UFLS) is to balance generation and load when an event causes a significant drop in frequency of an interconnection or islanded area. Such occurrences are very few, and little value from trending is available. Additionally, the metric M-2 captures emergency automatic load shed including load shedding of 100 MW or greater associated with UFLS operation.

M-8 (ALR3-5) Interconnection Reliability Operating Limit Exceedances

Background

The *State of Reliability 2014* report reviewed the IROL/System Operating Limit (SOL) Exceedances metric. In the past, this metric has been used to determine the number of times an IROL was exceeded in the Eastern Interconnection and the number of times an SOL was exceeded in the Western and ERCOT Interconnections. Since the metric was first introduced, all Regional Entities now recognize IROLs and are anticipated to be able to report on IROL exceedances in 2014. Therefore, M-8 (ALR3-5) was modified to remove the SOL reporting language in late 2013.

[53] Current recommended IFRO values are presented in the Frequency Response Annual Analysis, February 2015, Annual Analysis, http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf.

This metric measures the number of times that a defined IROL was exceeded and the duration of the exceedances. Exceeding an IROL could lead to widespread outages if prompt operator control actions are not taken to return the system to within normal operating limits. In addition, exceeding the limits may not directly lead to an outage but may put the system at unacceptable risk if the operating limits are exceeded beyond T_v.[54] The data is grouped into four time segments to monitor how quickly an IROL is returned to within normal limits, as shown in Table 4.10.

Table 4.10: Exceedance Duration Segment

Time Range	IROL/SOL Duration
Time Range 1	10 seconds < Duration ≤ 10 minutes
Time Range 2	10 minutes < Duration ≤ 20 minutes
Time Range 3	20 minutes < Duration ≤ 30 minutes
Time Range 4	Duration > 30 minutes

Eastern Interconnection

Figure 4.8 shows the number of IROL exceedances by quarter and time range of exceedance for the Eastern Interconnection for 2011 through 2014. The second quarter consistently shows the most exceedances for the Eastern Interconnection in all years due to planned transmission outages that result in congestion and higher flows on the remaining paths.

In 2013 and 2014, the number of exceedances is similar in all four seasons, rather than heavily weighted toward the off-peak seasons when most planned outages occur. Also in 2013 and 2014, there were exceedances that had durations that put them into Time Range 3 and Time Range 4, meaning that the duration of these exceedances was greater than 20 minutes; some were greater than 30 minutes. Taken together, it appears that in the Eastern Interconnection, exceedances are occurring for longer periods of time, and there was a notable increase in total occurrences, particularly in Time Range 1.

Also, the number of Time Range 1 exceedances increased significantly in 2014 compared to the other years for which data is provided. This may be explained by the fact that a new Energy Management System (EMS), which logs all defined IROL limit exceedance alarms, was installed in late 2013 at one of the RCs. All defined IROL exceedance limit alarms are also archived, allowing for sampling of the data for reporting purposes. The RC also implemented a new monitoring tool whereby the granularity of the monitoring has been decreased from 60 seconds to 10 seconds, which will inherently pick up more IROL exceedances. Therefore, the increase in the number of Time Range 1 events in 2014 is attributed to the new EMS system as well as the monitoring tool. It is anticipated that measurements for future years will also be impacted by the monitoring changes made for 2014. Based on this anticipated result, the parameters for reporting on Time Range 1 should be examined to ensure that the correct information is being captured.

[54] T_v is the maximum time that an IROL can be violated before the risk to the Interconnection or other RC Area(s) becomes greater than acceptable. Each IROL's T_v shall be less than or equal to 30 minutes.

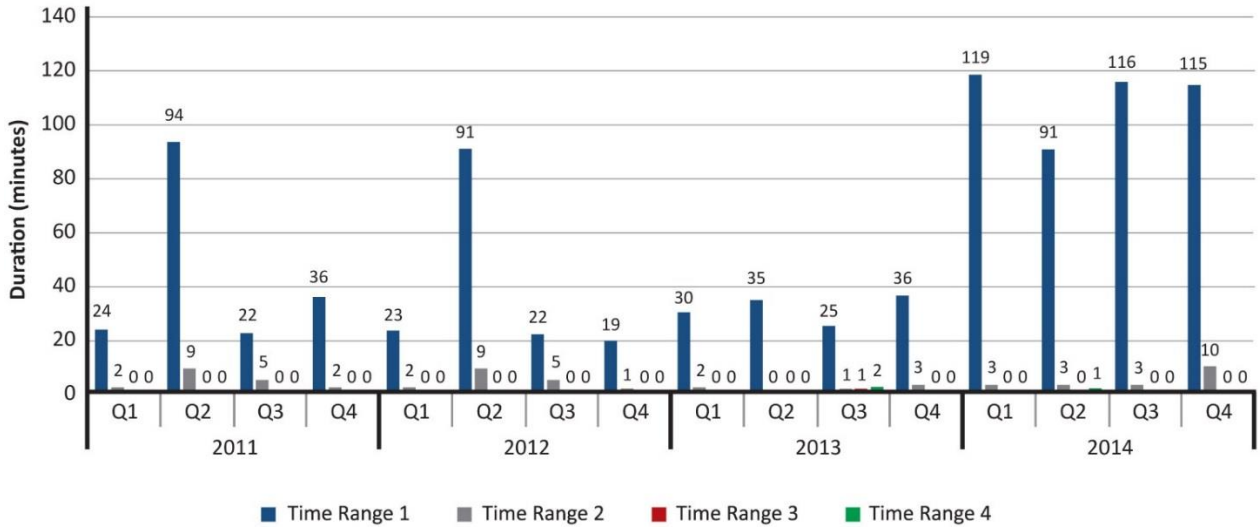


Figure 4.8: Eastern Interconnection IROL Exceedance

Western Interconnection

The year 2014 was the first time the RC in the Western Interconnection was able to report on IROL exceedances because of changes to allow the calculation of IROL limits. As a result, M-8 was reviewed and updated to reflect IROL reporting from the Western Interconnection. For the year 2014, reported IROL data does not show any IROL exceedances for the Western Interconnection. The Western Interconnection RC's definition of an IROL has additional criteria that may not exist in other RC areas.

ERCOT Interconnection

Figure 4.9 shows that the number of IROL exceedances was greatly reduced from 2011 through 2014. The drop in IROL exceedances between the fourth quarter of 2012 and the first quarter of 2013 is attributed to the completion of a major transmission expansion project. The result is that the IROL that contributed to most of the exceedances (the West-to-North (W-N) IROL) was retired in 2013. In the past, the W-N IROL limit was the sole source of IROL exceedances.

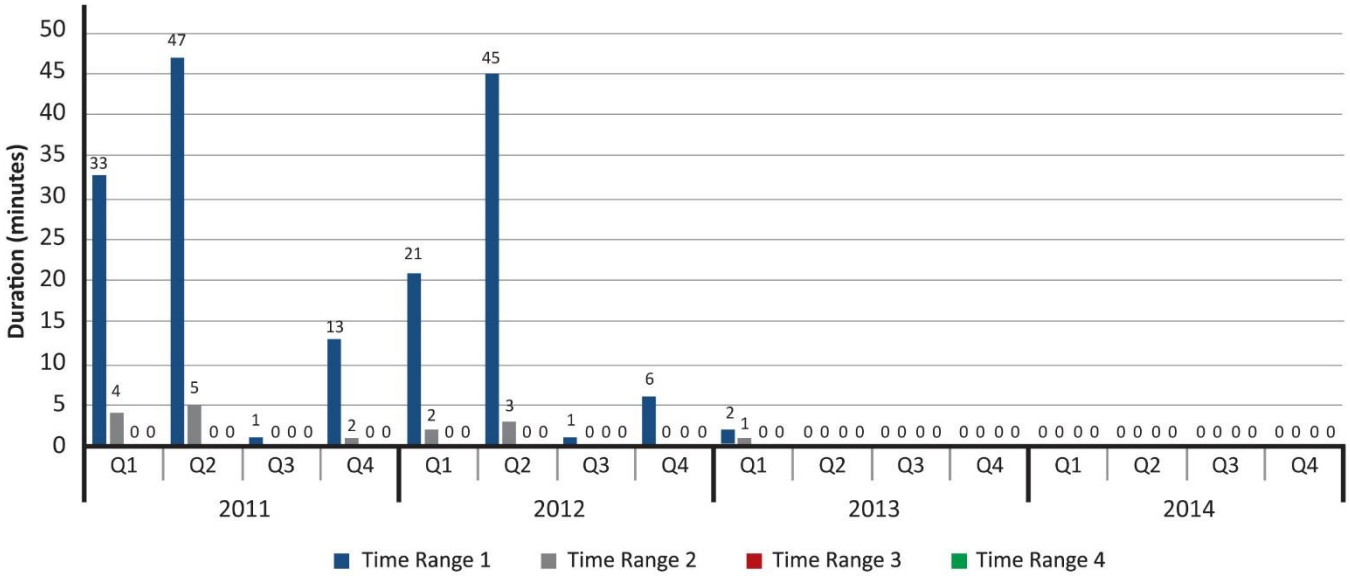


Figure 4.9: ERCOT Interconnection IROL Exceedances

M-9 (ALR4-1) Correct Protection System Operations

Background

In 2013, the metric was modified to focus on correct protection system operations, rather than focusing solely on misoperations. Therefore, in this report, the focus of this metric will include an analysis of correct operations and a discussion of misoperations.

Protection system misoperations were identified as an area that requires further analysis in past state of reliability reports. The improvements to the data collection process that the Protection System Misoperations Task Force (PSMTF) and System Protection Control Subcommittee (SPCS) proposed in 2013 were implemented and have improved the accuracy of misoperation reporting. The PSMTF and SPCS recommendation that misoperation analysis be continued on an annual basis by the respective protection system subcommittees within each Regional Entity began in early 2014.

Assessment

Figure 4.10 shows the correct operations rate for NERC during the reporting period. This information has not been included in prior state of reliability reports, but is included here for the time period that the data is available.

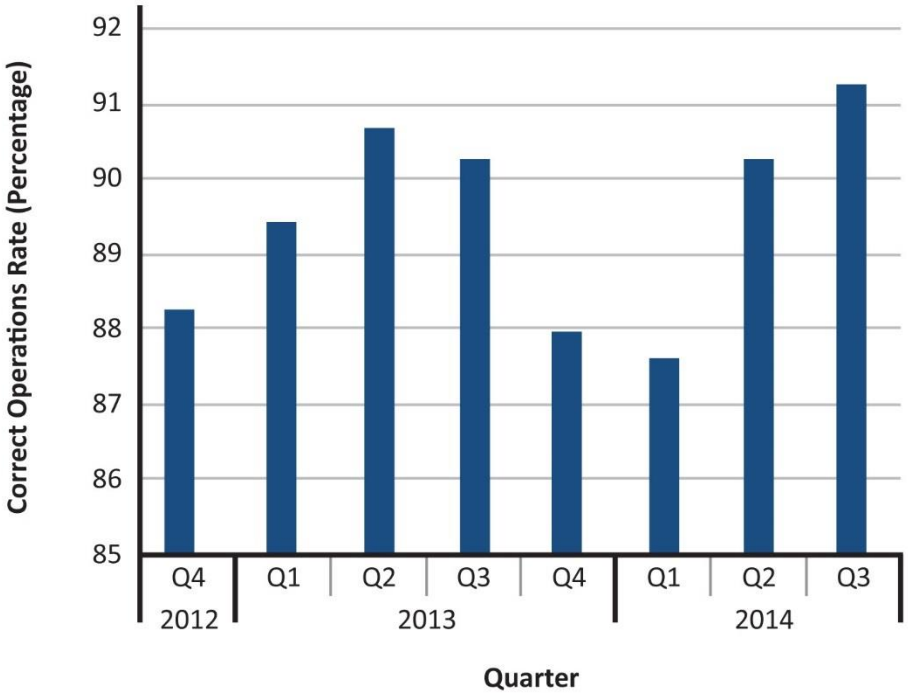


Figure 4.10: Correct Protection System Operations Rate

Figure 4.11 shows the misoperation rate by Region through the third quarter of 2014. The misoperation rate reflects the ratio of misoperations to total operations for the entire BES, 100 kV and above. This ratio provides a consistent way to trend the rate of misoperations as compared to a misoperation count alone, where weather and other factors can influence the count. Total protection system operations were first requested with the fourth quarter 2012 misoperation data.

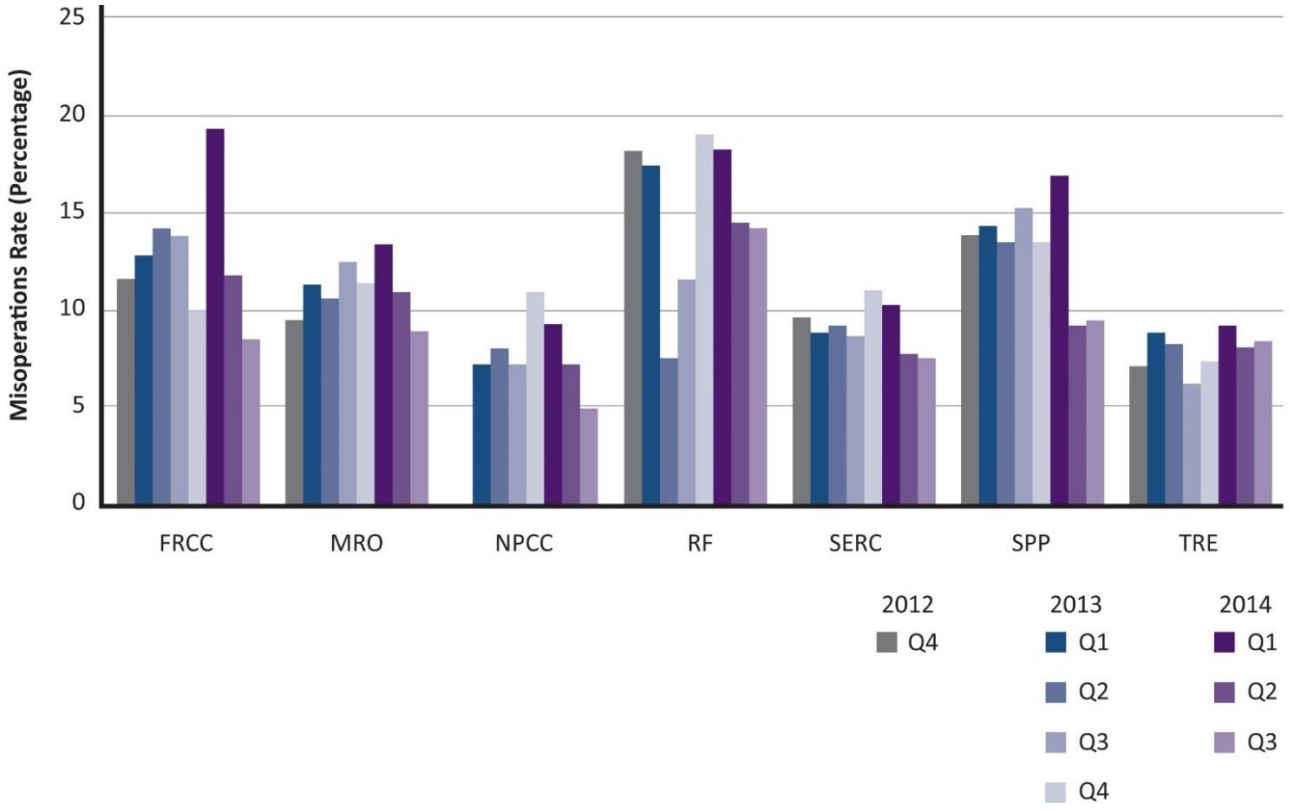


Figure 4.11: Protection System Misoperations by Region (2Q 2012–3Q 2014)

Figure 4.12 illustrates the top-three cause codes being assigned to misoperations by the TOs: incorrect setting, logic, or design error; relay failures/malfunctions; and communication failure. These three cause codes have consistently accounted for approximately 65 percent of all misoperations since data collection started in 2011.

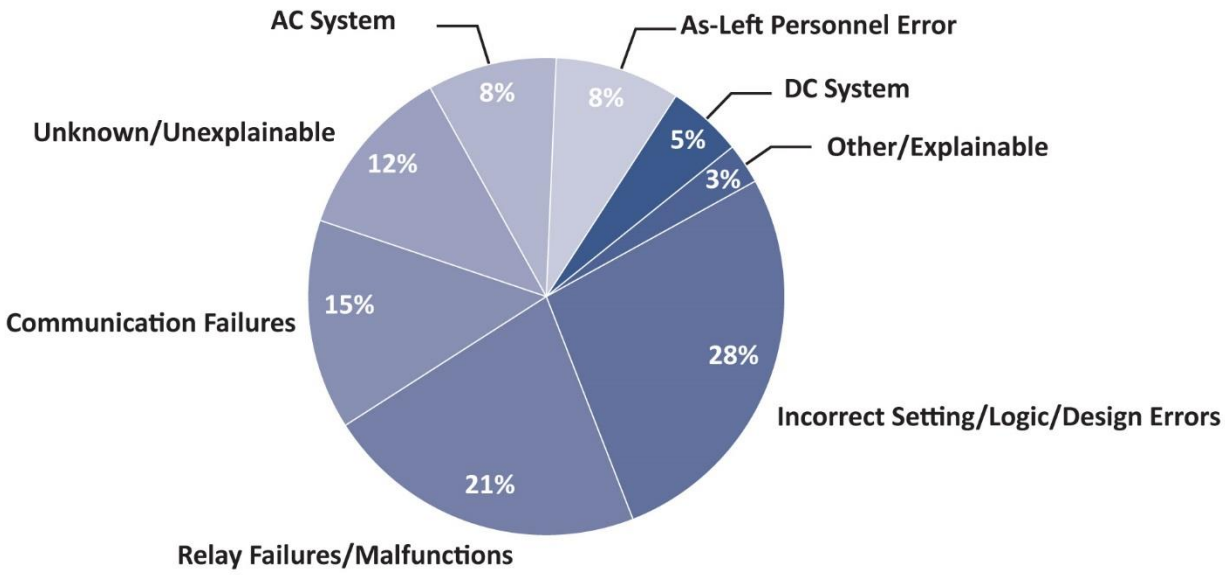


Figure 4.12: NERC Misoperations by Cause Code (2Q 2011–3Q 2014)[55]

Analysis of Data

Linkage between Reported Misoperations and Transmission-Related Qualified Events

An analysis of misoperation data and events in the Event Analysis Process provides two perspectives on misoperations. Out of approximately 2,000 total misoperations in 2014, approximately 2.5–3.0 percent were causal to or exacerbated the severity of reportable system disturbances. The other perspective is that more than 68 percent of transmission-related events have misoperations associated with them that either initiated the event or caused the event to be more severe. In 2014, there were 54 transmission-related system disturbances which resulted in a Qualified Event. Of those 54 events, 47 events, or about 87 percent, had associated misoperations. Of the 47 events, 37 of them (79 percent) experienced misoperations that were contributory to or exacerbated the severity of the event. In several cases, multiple misoperations occurred during a single disturbance.

Ground Instantaneous Overcurrent Settings

Additionally, 18 of the misoperations identified in Qualified Events were attributed to incorrect relay settings, with 11 of those 18 specifically attributed to incorrect ground overcurrent settings. The only Category 3 event in 2014 was directly related to an incorrect ground instantaneous overcurrent setting. Based on a review of misoperations in Qualified Events, there are two main causes of the incorrectly set ground instantaneous overcurrent elements. The first is an increase in the maximum value of ground fault short circuit current available over time, rendering the ground settings too sensitive. The second is setting the ground instantaneous overcurrent element without enough margin to accommodate short circuit modeling tolerances and other component anomalies. Entities were provided with information in 2014 to address these topics.

[55] Cause coded Misoperation data for 2014 4Q is not available at this point

Actions to Address Misoperations

NERC is in the process of revising a number of Reliability Standards that involve protection systems.[56] To increase awareness and transparency, NERC will continue to conduct industry webinars[57] on protection systems and document success stories on how GOs and TOs are achieving high levels of protection system performance. The quarterly protection system misoperation trending by NERC and the Regional Entities can be viewed on NERC's website.[58] In addition, NERC staff analyzed the top-three protection system misoperation cause codes reported on a quarterly basis by the Regions and NERC through compliance with Reliability Standard PRC-004-2.1a to identify Regional Entity trends and provide guidance to protection system owners that experience a high number of misoperations.[59] Incorrect setting/logic/design errors in microprocessor relays were found to be the largest source of misoperations in almost every Region. This further supports the idea that focus should be placed on setting/logic/design controls for microprocessor relays. Specific NERC and industry actions are identified in the report, with the expectation that the rate of misoperations due to these causes can be reduced by 25 percent by yearend 2017.

M-11 (ALR6-2) Energy Emergency Alerts

Background

This metric was enhanced in 2013 by expanding the data collection to include counts and duration of all EEA events of all levels, and unserved energy data for all EEA3 occurrences that result in load shedding. Going forward, this metric will account for the number and duration of all EEAs that are issued. All EEA1, EEA2, and EEA3 occurrences are now tracked to see whether there are any changes in frequency, duration, and load shed magnitudes associated with EEA occurrences over time.

As historical data is gathered on EEAs, trends provide a relative indication of performance measured at a Regional Entity or interconnection level. By definition, when an EEA3 alert is issued, firm load interruptions are imminent or in progress. An EEA3 indicates an issue with the real-time adequacy of the electric supply system. It may be due to a lack of fuel or dependence on transmission for imports into a constrained area, not simply a lack of available generation resources. The contributing factors for EEA3 events need to be considered.

The reporting of the duration and unserved energy of load shed events aids in determining the likelihood and duration of a load shed event following the issuance of an EEA3. EEA3 events are currently reported, collected, and maintained in NERC's Reliability Coordinator Information System (RCIS), as defined in Reliability Standard EOP-002-3.[60]

Assessment

Table 4.11 shows the number of EEA3 events from 2006 to 2014 at the Regional Entity level. Interactive quarterly trending is available on the Reliability Indicator's page.[61] In 2014, there were four EEA3 alerts issued with only one resulting in a loss of load event. The number of EEA3 events declared in 2014 is less than any other year for which data reporting exists.

[56] http://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx
[57] http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf
[58] http://www.nerc.com/pa/RAPA/ri/Pages/ProtectionSystemMisoperations.aspx
[59] http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/NERC Staff Analysis of Reported Misoperations - Final.pdf
[60] The latest version of EOP-002 is available at: http://www.nerc.com/files/EOP-002-3_1.pdf.
[61] The EEA3 interactive presentation is available on the NERC website at: http://www.nerc.com/pa/RAPA/ri/Pages/EEA2andEEA3.aspx.

Table 4.11: Energy Emergency Alert 3									
Region	Number of Events								
	2006	2007	2008	2009	2010	2011	2012	2013	2014
NERC	**7**	**23**	**12**	**41**	**11**	**23**	**16**	**7**	**4**
FRCC	0	0	0	0	0	0	0	1	2
MRO	0	0	0	0	0	0	0	0	0
NPCC	0	0	1	1	0	0	0	0	1
RF	0	3	1	0	2	0	1	0	0
SERC	4	14	2	3	4	2	7	0	1
SPP	1	5	3	35	4	15	6	2	0
TRE	0	0	0	0	0	1	1	0	0
WECC	2	1	5	2	1	5	1	4	0

One EEA3 event that resulted in load shed involved the interruption of 100 MW of load for 3.33 hours, and an additional 200 MW of load for 2.5 hours, or unserved energy of 833 MWh. This event was due to conditions during the polar vortex that resulted in record-low temperatures and high demand.

The other three reported EEA3 alerts did not result in any loss of load events. These EEA3 events generally fell into the category of a local area with transmission limitations such that the local area could not make use of the reserves that existed within the Region. In these cases, all local generation resources were in use, and transmission limitations restricted the ability to get resources from the Region, which had reserves available.

Since 2013, EEA Level 1 and Level 2 events are also assessed as a part of this metric. Table 4.12 shows the number of EEA events at each of the levels by Regional Entity. More events occur at Level 1 and Level 2, as those represent situations in which capacity emergencies are developing.

Figure 4.13 displays the cumulative amount of time at each EEA alert level. This data for all the alerts was only collected for 2013 and 2014. This graph shows that the duration of EEA3 events for which no load was lost was lower in 2014 than in 2013. Except for the one EEA3 event for which load was lost, both the amount of load lost and the duration of the event were greater than in 2013.

Table 4.12: 2014 EEA Level by Region				
Region	EEA1	EEA2	EEA3	Total
FRCC	0	2	2	4
MRO	10	12	0	22
NPCC	1	3	1	5
RF	3	6	0	9
SERC	2	7	1	10
SPP	1	2	0	3
WECC	1	3	0	4
TRE	1	1	0	2
Grand Total	**19**	**36**	**4**	59

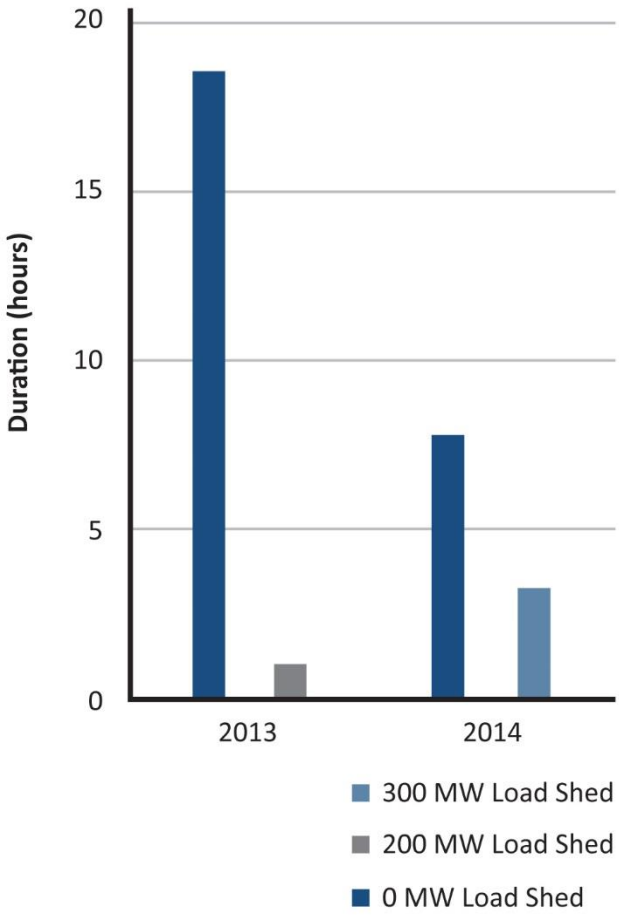


Figure 4.13: Firm Load Shed and Duration Associated with EEA3 Events by Year

M-12 (ALR6-11) Automatic AC Transmission Outages Initiated by Failed Protection System Equipment

Background

This metric was enhanced in 2014 to be consistent with the collection of BES data in TADS. Originally, this metric collected a "normalized count (on a per-circuit basis) of 200 kV and above ac Transmission Element outages (i.e., TADS momentary and sustained Automatic Outages) that were initiated by Failed Protection System Equipment." Since the definition of BES was changed to include equipment down to 100 kV in some circumstances, this metric was revised to include any BES ac Transmission element outages that were initiated by the TADS ICC of Failed Protection System Equipment. The new BES definition became applicable July 1, 2014. However, the addition of TADS reporting for voltage classes less than 100 kV (BES only) and 100 to 199 kV begins for calendar year 2015. Therefore, 2014 data presented below is only for ac transmission element outages 200 kV and above. Figure 4.14 presents the number of automatic outages per circuit for the time period 2010 to 2014, and Figure 4.15 presents the number of automatic outages per transformer for the time period 2010 to 2014.

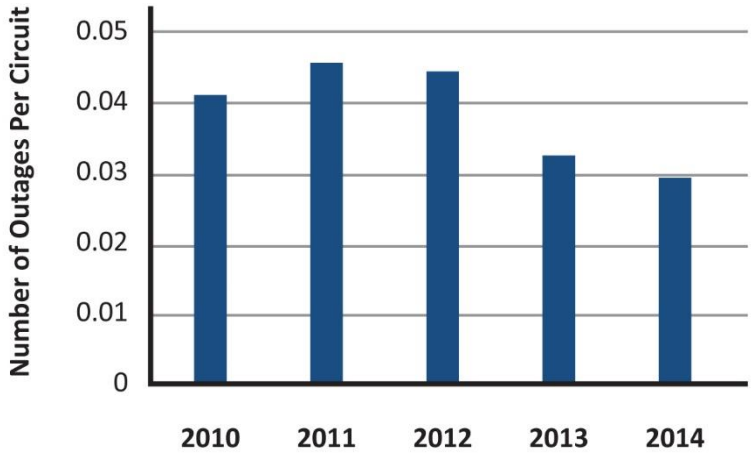


Figure 4.14: Automatic AC Circuit Outages Initiated by Failed Protection System Equipment

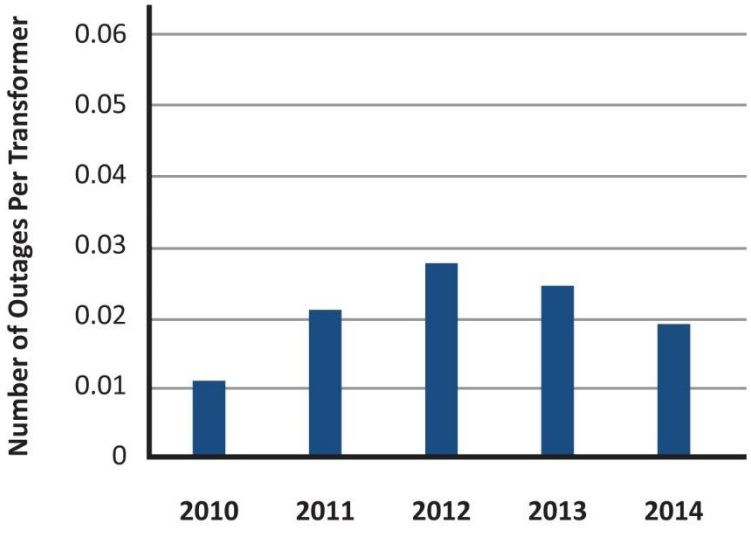


Figure 4.15: Automatic Transformer Outages Initiated by Failed Protection System Equipment

M-13 (ALR6-12) Automatic AC Transmission Outages Initiated by Human Error

Background

This metric was enhanced in 2014 to be consistent with the collection of BES data in TADS. Originally, the metric collected a "normalized count (on a per-circuit basis) of 200 kV and above ac Transmission Element outages (i.e., TADS momentary and sustained Automatic Outages) that were initiated by Human Error." Since the definition of BES was changed to include equipment down to 100 kV in some circumstances, this metric was revised to include any BES ac transmission element outages that were initiated by the TADS ICC of Human Error. Data for 2014, presented below, is only for ac transmission element outages 200 kV and above. Figure 4.16 presents the number of automatic outages per circuit for the time period 2010 to 2014, and Figure 4.17 presents the number of automatic outages per transformer for the time period 2010 to 2014.

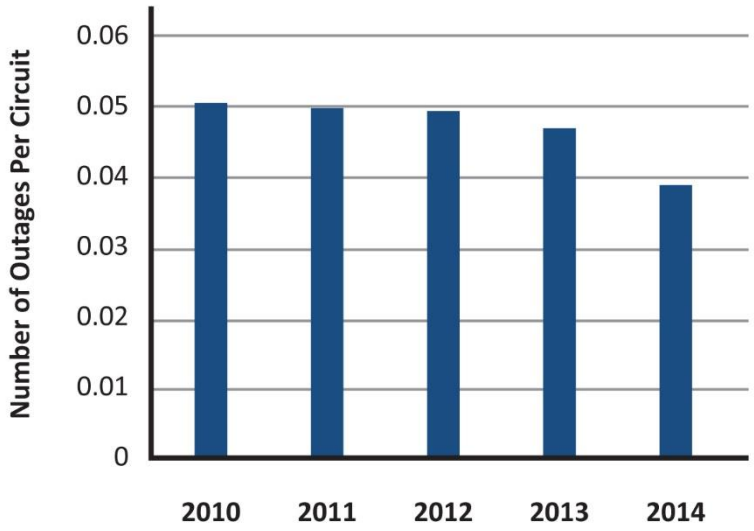


Figure 4.16: Automatic AC Circuit Outages Initiated by Human Error

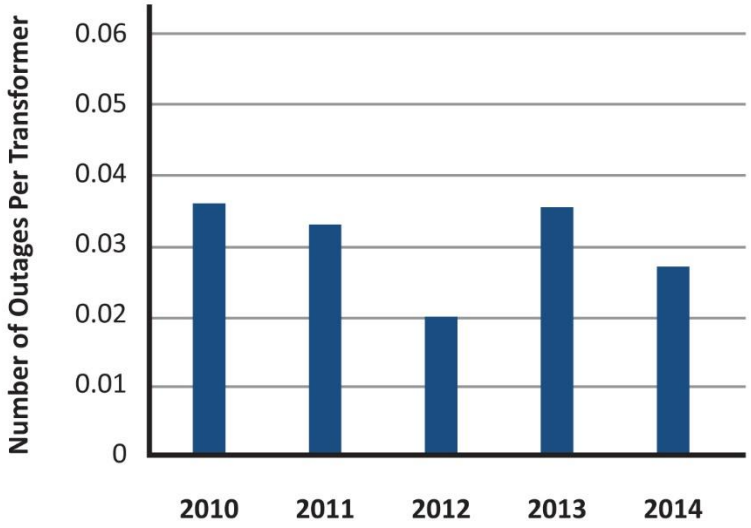


Figure 4.17: Automatic Transformer Outages Initiated by Human Error

M-14 (ALR6-13) Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

Background

This metric was enhanced in 2014 to be consistent with the collection of BES data in TADS. Originally, the metric collected a "normalized count (on a per-circuit basis) of 200 kV and above ac Transmission Element outages (i.e., TADS momentary and sustained Automatic Outages) that were initiated by Failed AC Substation Equipment." Since the definition of BES was changed to include equipment down to 100 kV in some circumstances, this metric was revised to include any BES ac transmission element outages that were initiated by the TADS ICC of Failed AC Substation Equipment. Data for 2014, presented below, is only for AC Transmission Element outages 200 kV and above. Figure 4.18 presents the number of automatic outages per circuit for the time period 2010 to 2014, and Figure 4.19 presents the number of automatic outages per transformer for the time period 2010 to 2014.

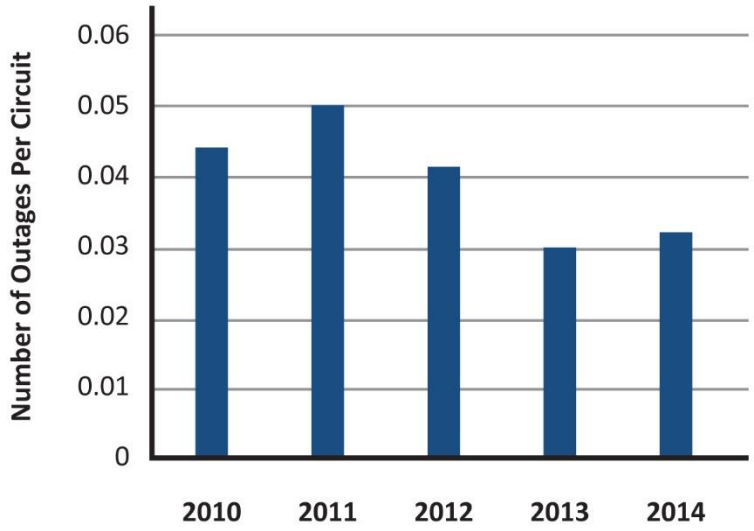


Figure 4.18: Automatic AC Circuit Outages Initiated by Failed AC Substation Equipment

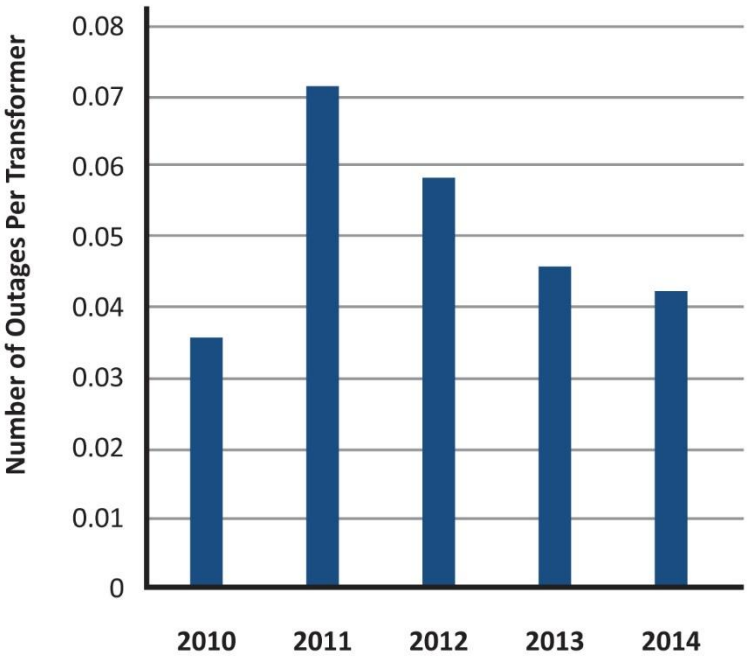


Figure 4.19: Automatic Transformer Outages Initiated by Failed AC Substation Equipment

M-15 (ALR6-14) Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Background

This metric was enhanced in 2014 to be consistent with the collection of BES data in TADS. Originally, the metric collected a "normalized count (on a per circuit basis) of 200 kV and above ac Transmission Element outages (i.e., TADS momentary and sustained Automatic Outages) that were initiated by Failed AC circuit equipment." Since the definition of BES was changed to include equipment down to 100 kV in some circumstances, this metric was revised to include any BES ac transmission element outages that were initiated by the TADS ICC of Failed AC Circuit Equipment. Data for 2014, presented below, is only for ac transmission element outages 200 kV and above. Figure 4.20 presents the number of automatic outages per circuit per 100 miles for the time period 2010 to 2014.

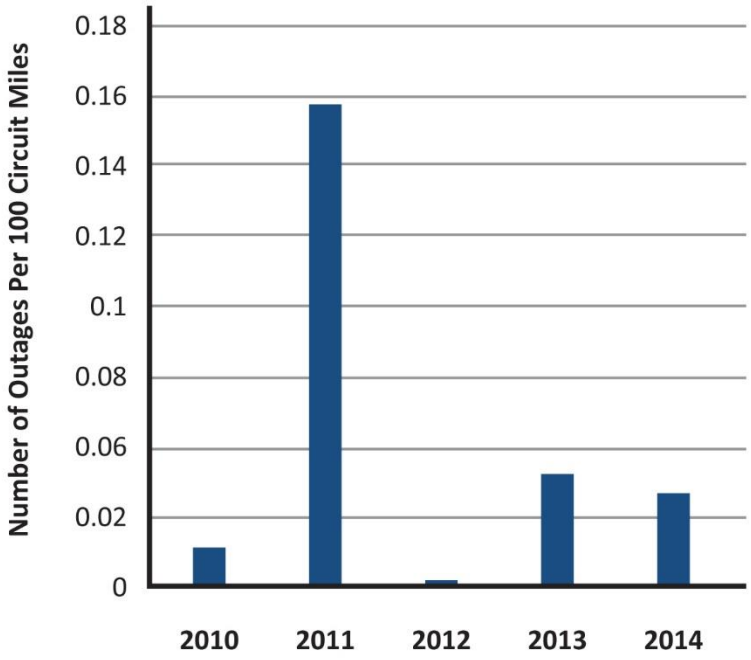


Figure 4.20: Automatic AC Circuit Outages Initiated by Failed AC Circuit Equipment per 100 Miles

M-16 (ALR6-15) Element Availability Percentage (APC) & Unavailability Percentage

Background

This metric was enhanced in 2013 to combine the Element Availability and Unavailability into one metric. Originally, there were two metrics: one to calculate availability and one to calculate unavailability. This metric continues to focus on availability of elements at 200 kV and above, because the components of the calculation include planned outages (which will no longer be collected in TADS beginning in 2015), unplanned outages (which are collected in TADS for all BES Elements), and operational outages (which are only collected in TADS for 200 kV and above). Therefore, the reporting voltage levels for this will not change. Figure 4.21 presents ac circuit availability as a percentage for the time period 2010 to 2014, and Figure 4.22 presents transformer availability as a percentage for the time period 2010 to 2014.

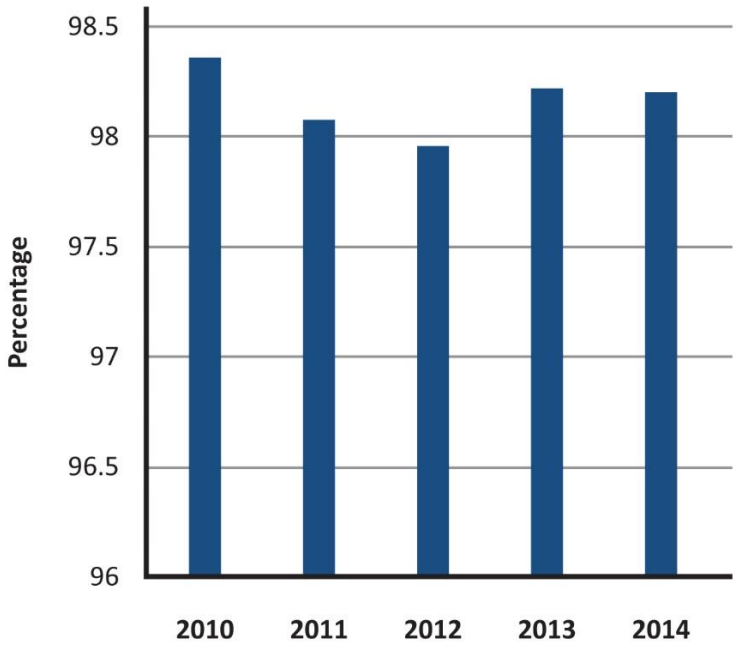


Figure 4.21: AC Circuit Availability

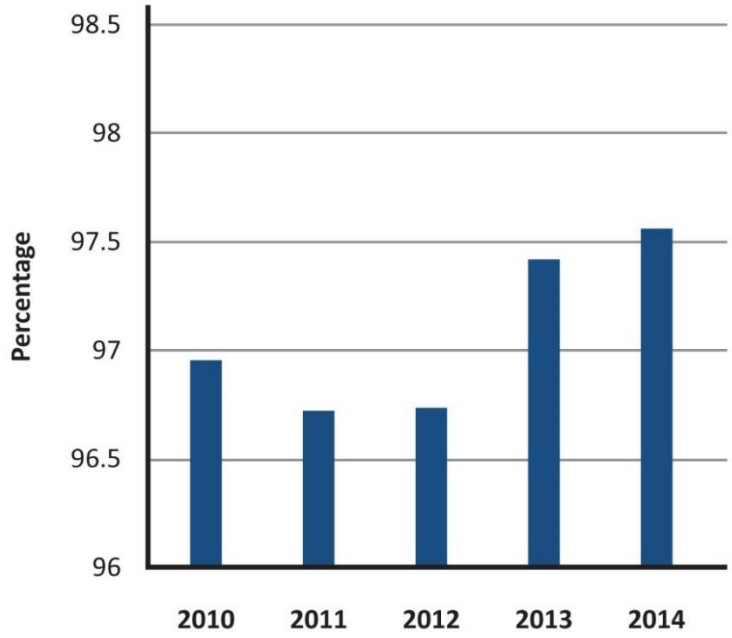


Figure 4.22: Transformer Availability

Chapter 5 – Development of Compliance Metrics

Background

NERC has continuously enhanced the Compliance Monitoring and Enforcement Program since 2008, providing more certainty on actions, outcomes, and reliability consequences. In August of 2010, the Reliability Metrics Working Group released its *Integrated Bulk Power System Risk Assessment Concepts*[62] paper introducing new concepts, such as the "universe of risk" of the BPS, which is illustrated in Figure 5.1. One of these concepts, the SRI, was developed as a way to assess the event-driven risk to the BPS. The ALR metrics were developed to assess the condition-driven risk. And the first attempt at a metric to track the impact of standard-driven risks of compliance violations was the Key Compliance Monitoring Index (KCMI).

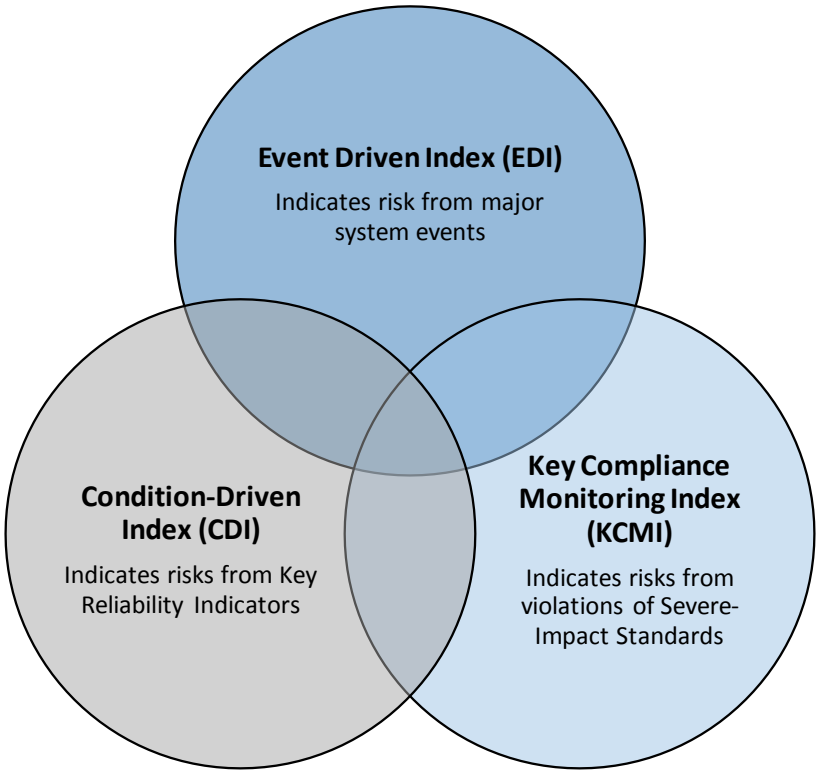


Figure 5.1: Conceptual Diagram of Risk Indices

The five-year assessment of the KCMI indicated that the risk to BPS reliability based on the number of violations of NERC Reliability Standards trended lower from 2008 to 2012. However, over the years, the Reliability Standards and language in the requirements underwent several modifications. New Reliability Standards and requirements were added, and others retired, but these changes were not reflected in the KCMI calculation. It proved difficult to maintain meaningful tracking of the data. Therefore, in late 2013, the OC and the PC acted to retire KCMI as a compliance metric and tasked the PAS with developing a replacement metric to allow for the meaningful collection of data concerning industry performance pertaining to compliance violations.

In June 2014, the RISC asked the CCC to identify ways compliance data can be used to create measures to reduce risk to the BPS. This request was based on a NERC Board request to the RISC in February 2013:

[62] http://www.nerc.com/comm/PC/Performance Analysis Subcommittee PAS DL/Archive/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf.

FURTHER RESOLVED, the Board hereby directs NERC management to work with the RISC and, as appropriate, NERC committee leadership to consider how NERC should utilize a data-driven reliability strategy development process that integrates with budget development and overall ERO planning (e.g., Standing Committee planning, department and employee goal setting).

Separately tasked with determining methods and metrics to reflect the risk of noncompliance to the reliability of the BPS, the two groups formed a team to address the development of one or more compliance-based metrics that relate to the reliability of the BPS. The concepts presented in this chapter describe two metrics that the team has developed in response to the tasks presented by the RISC, the OC, and PC.

CP-1 Risk Metric

A New Concept for Evaluating Risk to the BES, CP-1

The CCC and PAS proposed a new metric that relies on the ERO Enforcement staff's determination of the risk of a potential violation. As a violation progresses through enforcement, it is assigned situation-specific risk based on the facts and circumstances of the case. The most egregious violations are deemed "Serious Risk." Specifically, the team recommended tracking violations in the quarter they occurred. This focused the new metric more on newly discovered and reported possible violations (PVs).

CP-2 Impact Metric

Description

Compliance Metric 2 (CP-2) is a quarterly count of the number of newly reported noncompliances with observed reliability impact.

While the CP-1 (Risk) metric is expected to provide value to the ERO Enterprise, it has two primary limitations:

- While feedback loops will improve the quality of the risk assessments, there still is some subjectivity in the assignment of risk.
- Serious-Risk violations are relatively rare events, so tracking them provides limited information.

Error! Reference source not found. Figure 5.2 depicts the risk breakdown of violations processed in 2013 and 2014. Consistent with trends observed from 2008–2012, very few violations were deemed Serious Risk. Since BES impact is a manifestation of risk, the determination of the actual reliability impact of a PV is another aspect that could provide significant benefit in trending. The team's proposed CP-2 provides a measure of the observable BES impact due to compliance violations.

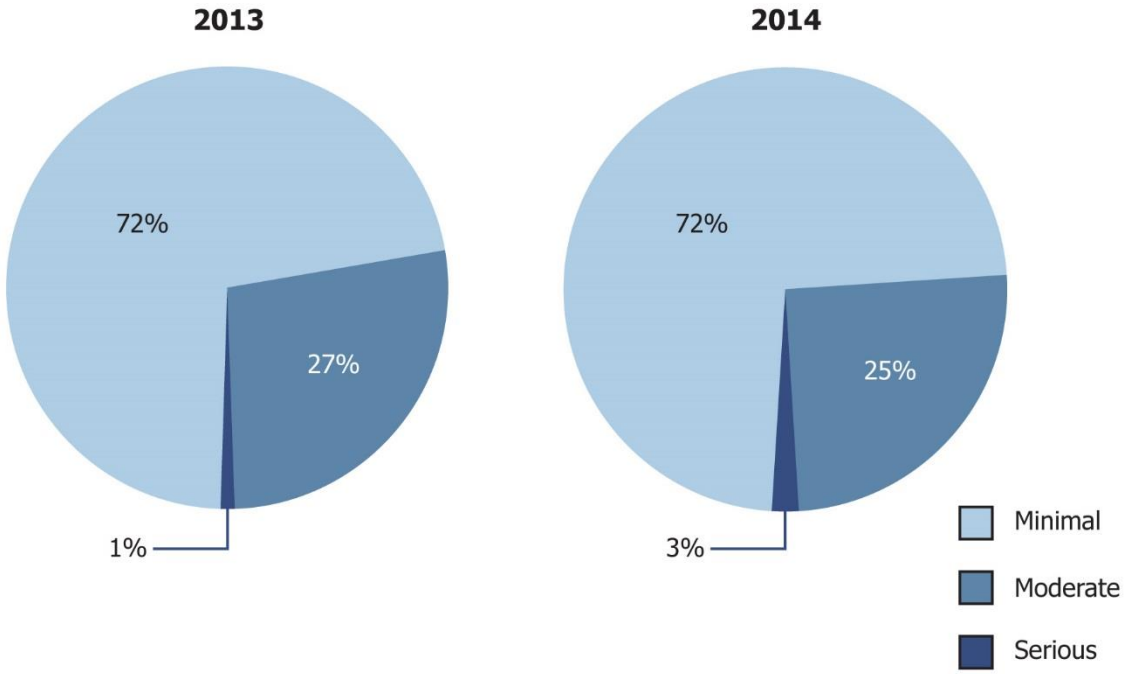


Figure 5.2 Final Risk Assessments (2013 and 2014)

The starting point for the metric is identification of a PV. For each PV reported, an assessment would be made as to whether there was an observable reliability impact from that violation. Unlike the assessment of risk, this metric focuses on the actual impact, not the potential impact of the violation.

To follow this approach to reduce the impact of standard violations on the BES, an assessment of the observable reliability impact needs to be made.

Figure 5.3 maps the four data tiers that define the impacts used for CP-2. This metric only requires capturing a small amount of data along with each Compliance Exception or PV. The observed impacts in the figure were used to advance the development of this report. The list is expected to evolve slightly over time based on experience.

It should be noted that Tier 2 and Tier 3 observations are relatively rare events. Of the approximately 1,200 violations processed in 2014, there were 25 Tier 3 violations and only a handful of Tier 2 cases. The value in the metric comes from verifying that the industry is looking for problems (Tier 0) and addressing the minor problems (Tier 1) before they can become large disturbances with more severe results.

The CCC approved the concepts and provided these concepts to the RISC in April of 2015. The PAS plans to recommend to the OC and PC the testing of these two compliance metrics: CP-1 (Risk Focus), and CP-2 (Impact Focus). These metrics should offer significant value in achieving the objectives above.

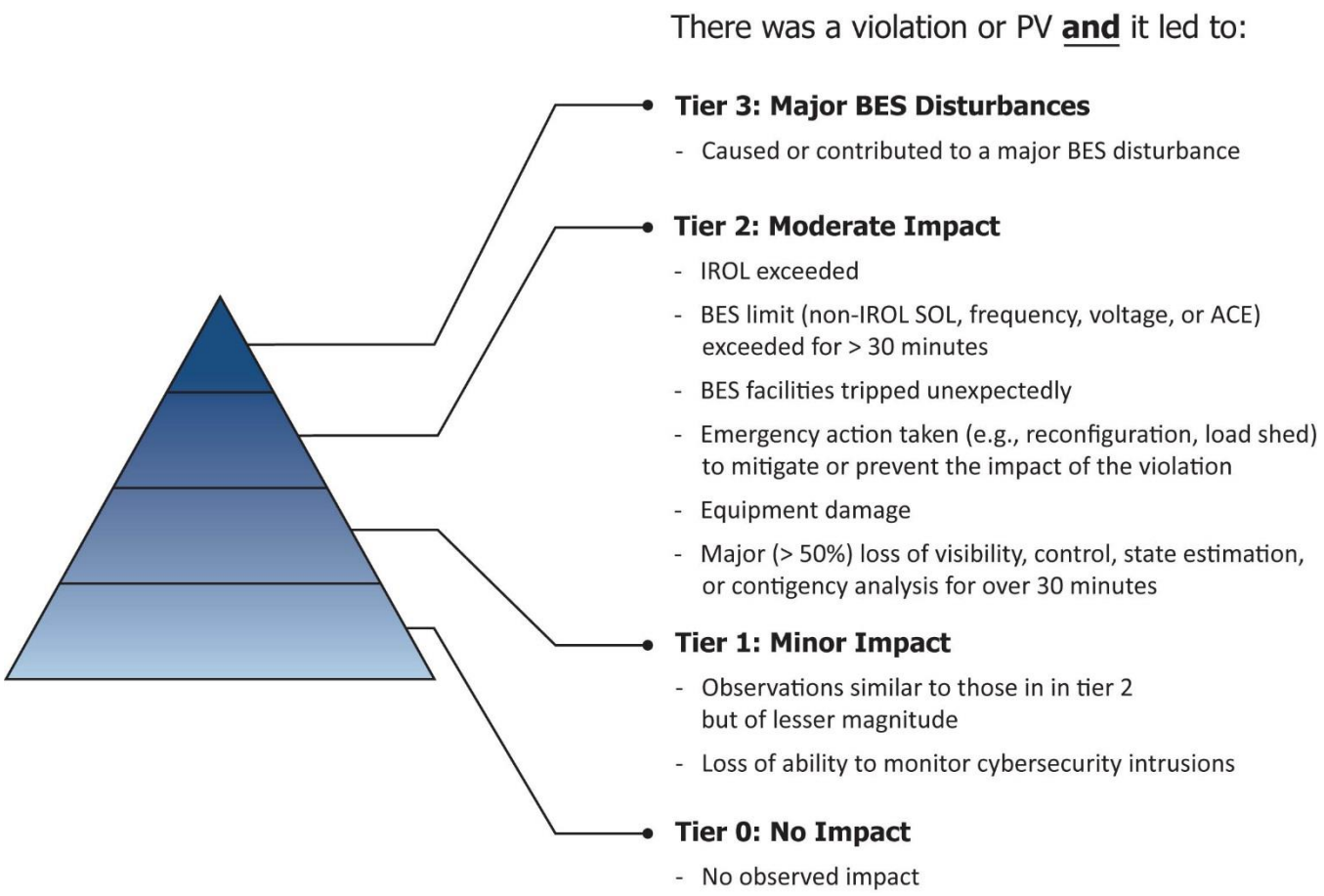


Figure 5.3: Impact Observations Mapped to the Impact Pyramid Tiers

Chapter 6 – Event Analysis

Background

The industry's voluntary ERO Event Analysis Process provides information to the ERO and industry to address potential reliability risks or vulnerabilities of the BPS. Since its initial implementation in October of 2010, the process has resulted in the collection of 569 Qualified Events and yielded 96 Lessons Learned, 19 of which were published in 2014.[63]

The first step in the ERO Event Analysis Process is Bulk Power System Awareness (BPSA), which monitors the BPS for reliability incidents that rise above a certain threshold of impact or risk. NERC's BPSA group and the eight Regional Entities monitor BPS conditions, significant occurrences, and emerging risks and threats across the 14 RC regions in North America. The 2014 information and products are provided in Figure 6.1, and a detailed description can be found in Appendix E.

Information	Products
Mandatory reports	252 daily reports
500 DOE OE-417 reports	33 special reports for significant occurrences
282 EOP-004-2 reports	4 security-related NERC Advisory (Level 1) Alerts for ES-ISAC
4 EOP-002-3 reports	1 reliability-related NERC Advisory (Level 1) Alert
Other information[64]	503 new Event Analysis database entries
1,741 Intelligent Alarms notifications	170 qualified Event Analysis Process events
2,356 FNet notifications and 602 FNet daily summaries	
6,172 WECCnet messages	
1,691 RCIS messages	
186 Space Weather Predictive Center Alerts	
1,789 assorted U.S. Government products	
3,588 assorted confidential, proprietary, or non-public products	
13,184 open source media reports	
1,257 Reliability Coordinator and ISO/RTO notifications	

Figure 6.1. Situational Awareness Inputs and Products in 2014

[63] The link to the NERC Lessons Learned page: http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx.
[64] Information sources listed in no particular order or priority, and not limited to these resources.

Analysis and Reporting of Events

Using the automated tools, mandatory reports, voluntary information sharing and third-party publicly available sources, disturbances on the grid are categorized by the severity of their impact on the BPS. Table 6.1 contains a consolidated chart of the reportable events since the program's inception (October 2010) and for 2014. For a more thorough review of the process, see: http://www.nerc.com/pa/rrm/ea/EA_Program_Document Library/Final_ERO_EA_Process_V2.1.pdf.

Table 6.1: Event Analysis Summary

Event Category	Count (Total)	Count (2014)	Comments
CAT 1	**412**	**144**	51 - Three or more BPS facilities lost (1a); 11 - Islanding (1b); 7 - BPS SPS/RAS Misoperation (1c); 1 - Voltage Reduction (1d) 10 - Control Room evacuations (1f); 2 - Generation lost (1g); 62 - Partial EMS (1h)
CAT 2	**137**	**24**	21 - EMS events (2b) 1 - Volt Excursion (2c) 1 - Unintended loss of load (2f) 1 - IROL (2g)
CAT 3	**15**	**1**	Loss of 2,103 MW generation (2 Nuclear units)
CAT 4	**3**	**0**	
CAT 5	**2**	**1**	Polar Vortex (2014)
Total CAT 1-5 Events	**569**	**170**	
Non-Qualified Occurrences Reported	**2050**	**333**	

Figure 6.2 is the control chart for the 569 Qualified Events through 2014. In October 2013, when Version 2 of the Event Analysis Process introduced the new category of events, collectively known as Category 1h (partial loss of EMS; see Appendix E for more information), occurrences that were not previously reported became reportable. The point in January 2014 where the number of reportable events exceeds the upper control limit[65] has been analyzed; results show an increase in the Category 1h events reported—out of an abundance of caution—when the mandatory reporting of EOP-004-2 went into effect.

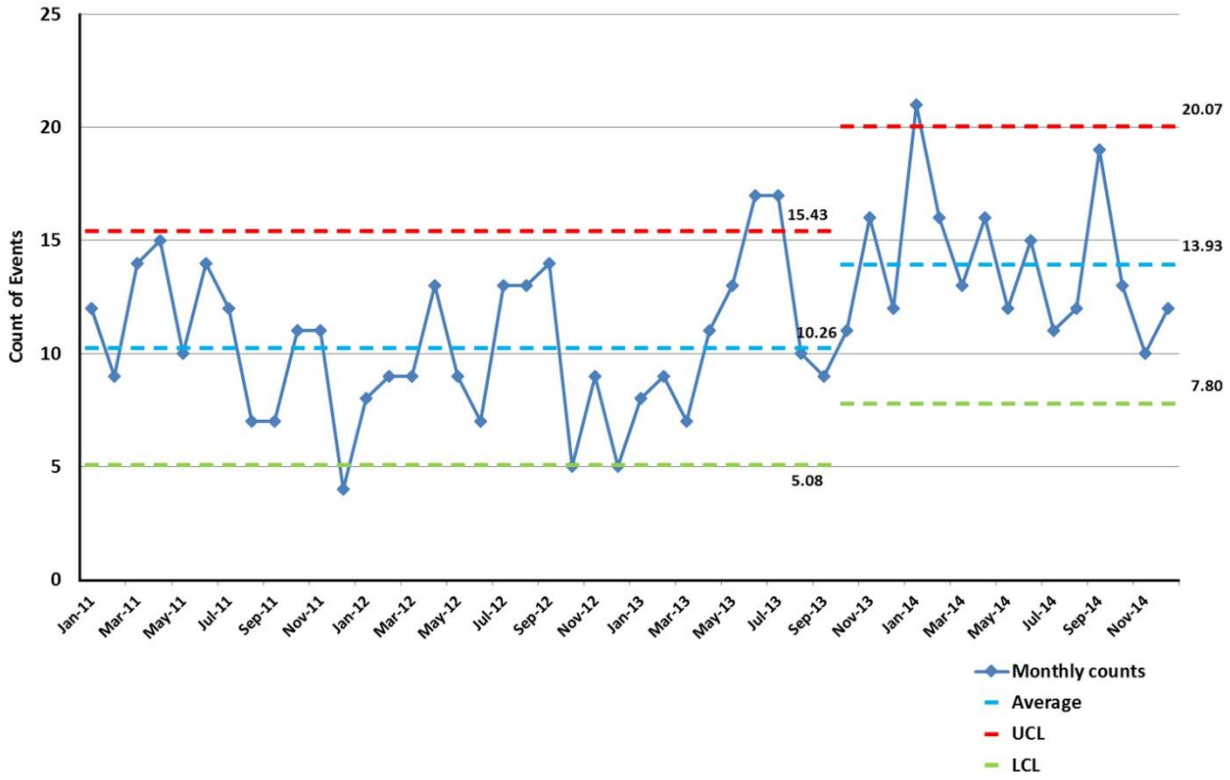


Figure 6.2. Control Chart – Number of Events (per Month) Over Time

A total of 342 contributing cause codes[66] were assigned to 401 events. The root cause of every event cannot be determined, though many of the contributing causes or failed defenses can be.

[65] The control limits are calculated using Statistical Process Control techniques as an Individuals-Moving Range (3-month moving average for the moving range) control chart.

[66] http://www.nerc.com/pa/rrm/ea/EA Program Document Library/CCAP_Manual_rev201503__Final_for_posting.pdf.

Figure 6.3 shows the overall trends for the contributing cause codes of events.

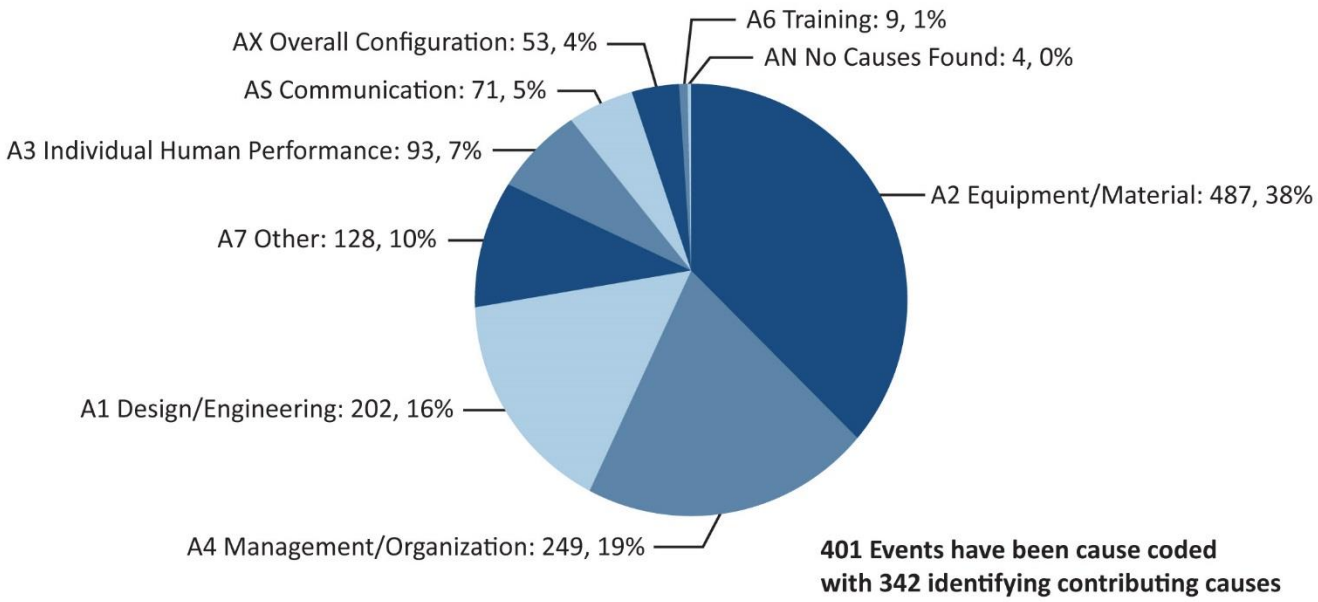


Figure 6.3. Percentage of Contributing Causes by Category

Identifying these large areas of concern makes it easier to prioritize and search for actionable threats to reliability. For example, analysis of the aggregate data identified different types of failed or damaged equipment. This information was turned over to the ACSETF for further investigation.

There was a single Category 3 event in 2014. The dominant issue in this event was the latent error of an incorrect setting of the directional ground instantaneous overcurrent (IOC) element on a numerical relay. NERC published a Lesson Learned in February 2015 titled *Consideration of the Effects of Mutual Coupling when Setting Ground Instantaneous Overcurrent Elements*. Similar issues have been seen in several smaller events.

Major Initiatives in Event Analysis

Human Performance

In Appendix A, human error is listed as a contributor to transmission outages. Event Analysis has identified workforce capability and human performance challenges as possible threats to reliability. Workforce capability and human performance is a broad topic and can most simply be divided into management, team, and individual levels. NERC held its third annual HP conference, Improving Human Performance on the Grid, in Atlanta in March 2014.

NERC continues to conduct cause analysis training with staff from the Regions and registered entities. As of December 2014, personnel from all eight Regions and approximately 1,000 people from 204 different registered entities have received cause analysis training (roughly 8,000 hours of training).

Polar Vortex Review

In 2014, NERC and the Regions engaged in an analysis of a major event that occurred across a significant footprint of North America. In early January of 2014, the Midwest, South Central, and East Coast regions of North America experienced a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20 to 30° F below average. Some areas faced days that were 35° F or more below their

average temperatures. These temperatures resulted in record-high electrical demand for these areas on January 6 and again on January 7, 2014.

Considerable resources were used to evaluate conditions, including information gathered during operations and data collected in GADS. NERC's *Polar Vortex Review*[67] shows that BPS reliability was maintained despite sustained record-low temperatures occurring over a large geographic area in North America. Many areas experienced daytime high and overnight-low temperatures that were between 20 degrees and 30 degrees below normal, with 49 cities setting new record lows.

GOPs and TOPs in North America responded well to prevent major impacts to the BPS. As expected, key factors during the event included fuel deliverability issues, natural gas pipeline outages, gas service interruptions, frozen electricity and gas equipment, and other extreme cold weather operating challenges. During the event, grid operators employed techniques such as voltage reduction and demand-side management to ensure that BPS reliability was maintained.

Event Severity Risk Index (eSRI)

Event Analysis calculates an Event Severity Risk Index (eSRI) for all Qualified Events (as defined in the ERO Event Analysis Process). The eSRI calculation follows the methodology provided in Appendix E and considers the loss of transmission, the loss of generation, and the loss of firm load along with the duration of the load loss.

Every Qualified Event since October 2010 reported through the ERO Event Analysis Process has its eSRI calculated. For the purposes of trending, certain event groups are excluded. The total number of events was 568; of these, 29 were attributed to islanding events for an entity that plans and operates to island as a normal contingency, 14 were weather-driven, and five were Category 4-5 events (three of which are also weather driven). Only two Category 4-5 events were excluded as Category 4-5 events, while three of them were excluded as weather-driven events. For more details on the exclusions and the eSRI formula, see Appendix E. A total of 523 event eSRI calculations are used for trending, as shown in Figure 6.4 and Figure 6.5.

[67] http://www.nerc.com/pa/rrm/January 2014 Polar Vortex Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

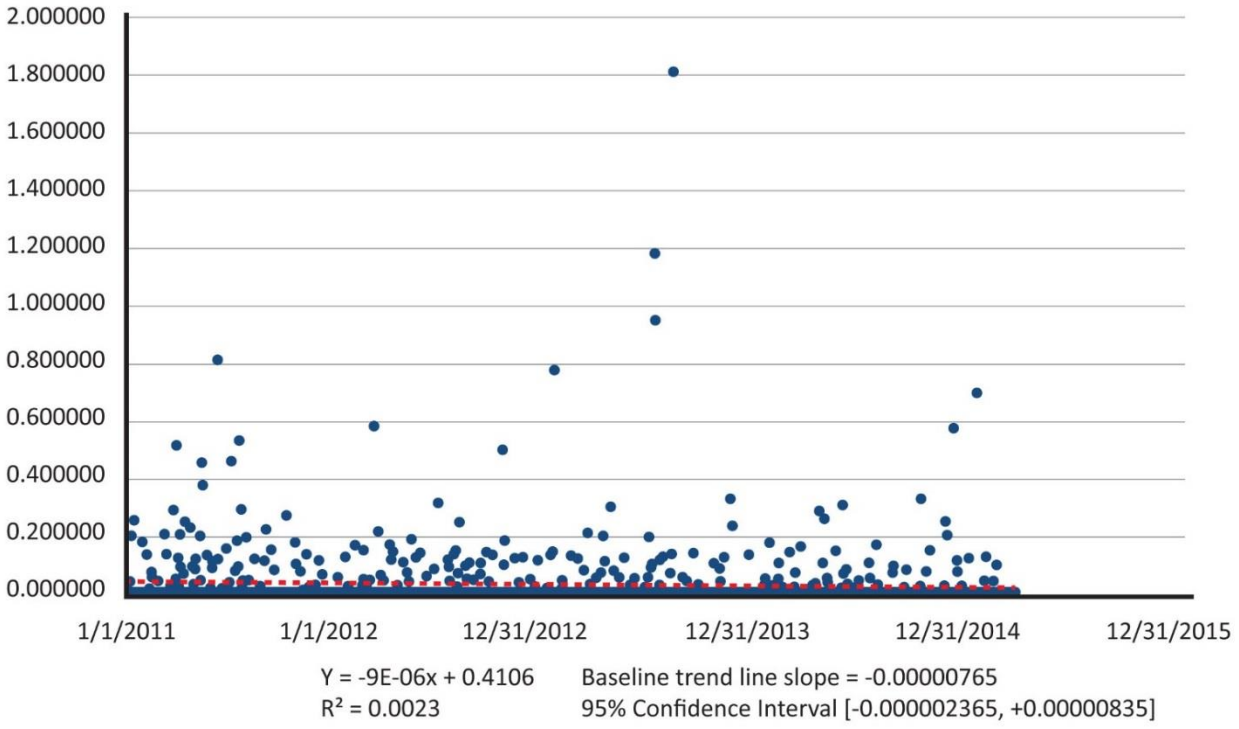


Figure 6.4: Trend Line of eSRI

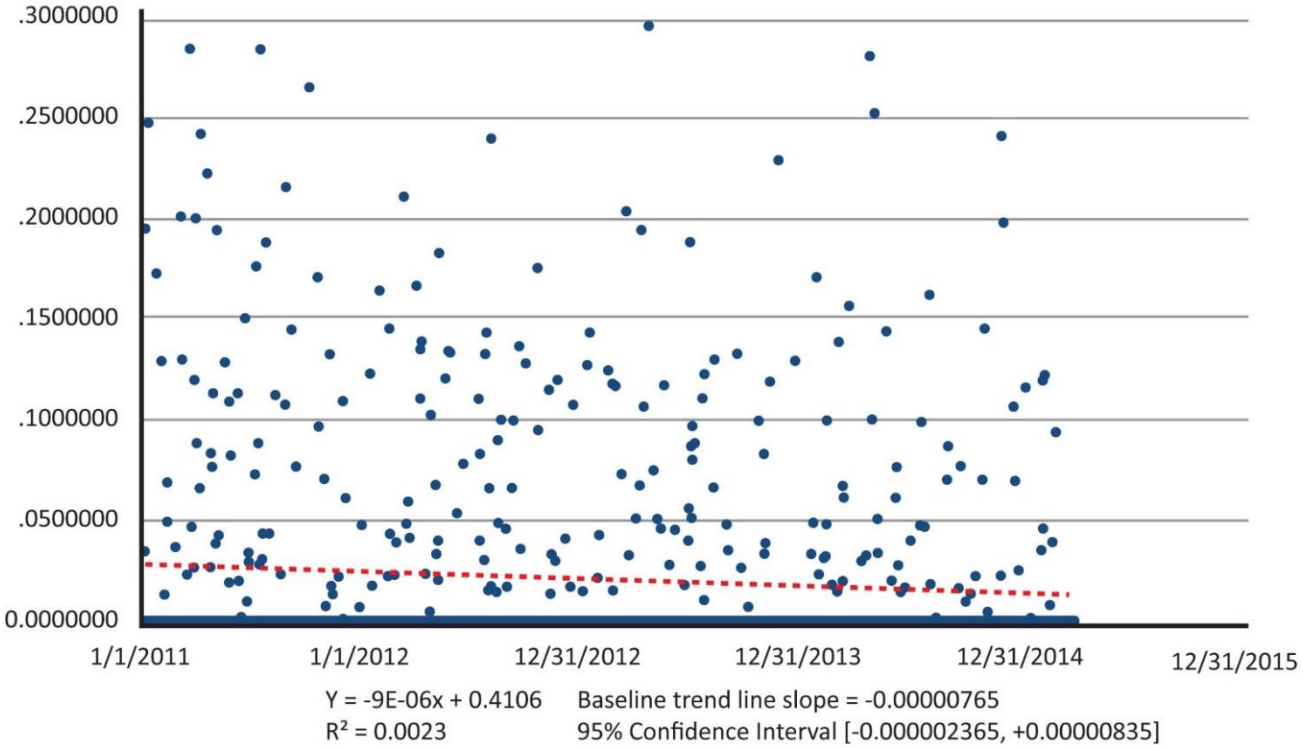


Figure 6.5: Expanded View of eSRI Trend Line Y Axis 0 to .3

As seen in the expanded view (included to address the scale limit visibility), the eSRI is approximately zero within the statistical confidence interval. Also, as indicated in Figures 6.4 and 6.5, the trend line is relatively flat.

Chapter 7 – Actions to Address Key Findings in Prior State of Reliability Reports

The state of reliability report contains key findings each year, many of which result in necessary actions for the PAS, NERC, and other subcommittees and working groups.[68] To track the actions that have been completed and those that are ongoing, a comprehensive table of action items identified in state of reliability reports from 2011 to 2014 is provided. In Table 7.1, the list of completed key actions is detailed and represents several years of response from industry to the items noted in previous state of reliability reports, while Table 7.2 shows those items that are still ongoing.

It is noteworthy that over these four years of reports, 22 items have been called out as actionable. During those same years, 18 of them have been completed. These have resulted in new processes, additional data and analysis, determination of risk, and modifications made to mitigate the risk. Four of them are still being addressed, but the expected resolution is on track for conclusion.

[68] Prior state of reliability reports can be found at the following locations:
http://www.nerc.com/comm/PC/Performance Analysis Subcommittee PAS DL/2011_RARPR_FINAL.pdf.
http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/2012_SOR.pdf.
http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/2013_SOR_May 15.pdf.
http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/2014_SOR_Final.pdf.

Table 7.1: Completed Key Finding Actions

Item Reference	Finding Report Year	Key Finding Type	Key Finding Heading	Key Finding Reference	Key Finding Words	Key Finding Status	Actions Taken to Date
1	2011	Transmission Performance	Transmission Availability Performance	Page 3 Paragraph 2	*"Almost one-third of all sustained, automatic outages are dependent or common mode events. A joint team should be formed to analyze these outages."*	Complete	Further clarification of key finding made, with subsequent formation of an IEEE working group, which continues to study this issue. Results of analysis on common and dependent mode outages was provided to the PC in 2012.
2	2011	Metric Assessment	Reliability Metric Performance	Page 2 Paragraph 3	*"All metrics will be evaluated on a regular basis to determine each metric's contribution to quantitative reliability measurement."*	Complete	Incorporated into routine metric review process and PAS scope. Reviewed, retired, and augmented metrics, in addition to annual review of BPS performance.
3	2011	Metric Assessment	Disturbance Events	Page 3 Paragraph 4	*"This suggests more data and analysis into equipment failure many prove fruitful. However, with such a small dataset, no conclusions can be drawn."*	Complete	Created Event Analysis Subcommittee and ERO Event Analysis Process with ongoing assessment of Qualified Events; subsequently, the ACSETF was formed, which further explored and investigated equipment failures.
4	2012	Metric Assessment	Bulk Power System Reliability Remains Adequate	Page 5 Paragraph 3	*"Investigation into load-loss events is recommended, including post-event review. Further, load-loss reporting should be refined to distinguish differences between consequential and non-consequential load loss, and include identification of initiating events."*	Complete	Load-loss events are analyzed in several different ways, including modifications to ALR1-4 (in 2013), which captures load-loss events in excess of 50 MW, and the modified SRI calculation method, both of which were approved by OC and PC. Additionally, consequential and non-consequential are addressed by factors collected during the ERO Event Analysis Process, where an eSRI is also calculated.
5	2012	Transmission Performance	Equipment Failure Warrants Further Analysis	Page 10 Paragraph 2,3	*"Additional data is needed to investigate equipment failure. Small subject matter expert technical group could be formed to further investigate and provide solutions."*	Complete	Targeted data collection conducted. Collaboration between NATF and NERC undertaken to facilitate identification of reliability risks due to particular types and models of equipment. ACSETF was formed to further investigate equipment failure; specific recommendations were made to the PC at its March 2015 meeting.

Table 7.1: Completed Key Finding Actions							
Item Reference	**Finding Report Year**	**Key Finding Type**	**Key Finding Heading**	**Key Finding Reference**	**Key Finding Words**	**Key Finding Status**	**Actions Taken to Date**
6	2012	Metric Assessment	Frequency Response is Stable with No Deterioration	Page 5 Paragraph 5	*"More data is still needed to apply statistical significance tests and calculate a confidence interval to establish a trend. Also additional analysis on time of year, load levels, generation on-line, and response withdrawal should be considered when interpreting the trend."*	Complete	Frequency response statistics and performance levels have been developed (with regard to assessing stability as a function of time, loading, etc.).
7	2012	Transmission Performance	Protection System Misoperations are a Significant Reliability Issue	Page 9 Paragraph 1	*"Deeper investigation into the root causes of protection system misoperations is a high priority. As announced, a Protection System Misoperation Task Force has been formed to analyze misoperations."*	Complete	New reporting requirements were introduced, misoperation cause codes created; PSMTF assembled and evaluated performance. Augmented TADS analyses were subsequently performed and incorporated into the state of reliability reports.
8	2013	Metric Assessment	Bulk Power System Reliability Remains Adequate	Page 9 Paragraph 2	*"The top 10 most severe events in 2012 were all initiated by weather. There were only three high-stress days (SRI greater than 5.0) in 2012 compared to six days in 2011."*	Complete	Refined SRI to incorporate improved load-loss calculation method; modified SRI calculation, which was approved by OC and PC.
9	2013	Metric Assessment	Reduced Standards Violations Risks	Page 12 Paragraph 1	*"A five year assessment of the Key Compliance Monitoring Index indicated improvement…suggesting that this improved compliance trends indicates a reduced risk to BPS reliability."*	Complete	Subsequently, the KCMI was retired and a new metric was developed that evaluates the compliance risk to reliability.
10	2013	Transmission Performance	AC Substation Equipment Failures are a Second Significant Contributor to Disturbance Events and Automatic Outage Severity	Page 15 Paragraph 2	*"NERC recommends that a small subject matter expert technical group be formed to further validate findings [re circuit breaker failure equipment involvement] to understand the contributing factors to circuit breaker failures and provide risk control solutions."*	Complete	ACSETF formed, developed analysis, recommended improvements in the report. The OC and PC approved the report and task force disbanded.

Table 7.1: Completed Key Finding Actions							
Item Reference	**Finding Report Year**	**Key Finding Type**	**Key Finding Heading**	**Key Finding Reference**	**Key Finding Words**	**Key Finding Status**	**Actions Taken to Date**
11	2014		Sustained High Performance for Bulk Power System Reliability	Page 11 Paragraph 1	*"Based on the SRI_{bps} and 16 metrics that measure the characteristics of an ALR, BPS reliability is adequate and within the defined acceptable ALR performance objectives."*	Complete	No specific action is required for this finding.
12	2014	Frequency Response	Frequency Response remains Stable	Page 15 Paragraph 1	*"From 2009 to 2013, the Eastern Interconnection, ERCOT Interconnection, Quebec Interconnection and Western Interconnection have shown steady frequency response performance, trending above the recommended IFRO at all times during the study period. The Eastern Interconnection showed a slightly downward trend in frequency response; however, this trend is not statistically significant. Recommendation: NERC will examine and develop root causes for incidents in 2013 where frequency response was less than the IFRO. NERC will determine additional actions, beyond those currently being worked on in NERC Standards that should be taken to maintain and improve frequency response performance."*	Complete	Frequency event data has been studied further as recommended in the *Frequency Response Initiative Report.* This analysis process is annually conducted and results in a report filed with FERC. It is expected that this periodic analysis will continue to support the state of reliability reports.
13	2012	Frequency Response	More Data and Research is Needed	Page 12 Paragraph 3	*"Many datasets and performance analyses conducted in this report are still in an early stage. A number of metrics are limited to occurrence count values; no additional details, such as duration and/or intensity are available to provide a better observation of how each occurrence impacts bulk power system reliability."*	Complete	In subsequent state of reliability reports and in routine application of metrics, further dimensions to metrics have been created where appropriate. As metrics are reviewed and applied, they are further clarified and additional facets to their collection, calculation and application are addressed. This is evidenced by recent changes to metrics such as M2 (previously titled ALR1-4) as well as M11 (previously titled ALR 6-2).

Table 7.1: Completed Key Finding Actions							
Item Reference	Finding Report Year	Key Finding Type	Key Finding Heading	Key Finding Reference	Key Finding Words	Key Finding Status	Actions Taken to Date
14	2013	Frequency Response	Steady Frequency Response	Page 12 Paragraph 3	*"The expected frequency response for each interconnection has been higher than the recommended interconnection frequency response obligation."*	Complete	Frequency response continues to be monitored and reported upon annually, with assessment against statistical limits. Conclusions are drawn from these analyses which are reported in a variety of reports, including the state of reliability reports.
15	2013	Transmission Performance	Protection System Misoperations are a Significant Contributor to Disturbance Events and Automatic Transmission Outage Severity	Page 13 Paragraph 1	*"[P]rotection system misoperations are identified as the leading initiating cause to disturbance events."*	Complete	The PSMTF was established and collected data; additional outage cause codes were created to further distinguish types of clearing, to support better analysis, which will lead to improved operations and fewer misoperations. Misoperations reporting was enhanced.
16	2014	Transmission Performance	Protection System Misoperations Cause Transmission Events	Page 16 Paragraph 2	*"Misoperations analysis has developed three different datasets to understand their impact. Based on these datasets, however, the relationship between the Misoperations Initiating Cause Code and transmission risk, and the positive correlation between misoperations and transmission severity, understanding and reducing misoperations should remain a focus of NERC and industry participants. Recommendation: NERC will complete development of Reliability Standard PRC-004-3 — Protection System Misoperation Identification and Correction. NERC will develop a plan and catalyze industry action to address the three most common causes of protection system misoperations (settings/logic/design*	Complete	PRC 04-3 was approved in 2013. NERC staff analyzed misoperation data in 2014 and presented findings to the Planning Committee, which contained recommendations.

Table 7.1: Completed Key Finding Actions							
Item Reference	Finding Report Year	Key Finding Type	Key Finding Heading	Key Finding Reference	Key Finding Words	Key Finding Status	Actions Taken to Date
					errors, communication failures, and relay failures)."		

Table 7.1: Completed Key Finding Actions							
Item Reference	Finding Report Year	Key Finding Type	Key Finding Heading	Key Finding Reference	Key Finding Words	Key Finding Status	Actions Taken to Date
17	2014	Transmission Performance	Substation Equipment Failures Impact Transmission Event Severity	Page 18 Paragraph 3	*"The AC Substation Equipment Task Force (ACSETF) was created to address high-priority reliability issues related to ac substation equipment. The failure data is currently being analyzed, and observations include; 1) circuit breaker failures have the highest percentage of failures; 2) top four subcomponents are interruptions, mechanism, trip coil and bushing; 3) inherent in circuit breaker failure is an increased probability that additional BPS elements will also be out of service; 4) inherent in transformer failure is an increased probability of longer outage duration; and 5) further data collection and analysis is needed, including maintenance strategies, bus configurations, and failure event SRI calculation. Recommendation: NERC will assess the implementation and effectiveness of the Level 1 NERC Advisory issued to address 345 kV SF6 puffer-type breaker failures. NERC will develop a plan with milestones to address the causes of substation equipment failures identified by the ACSETF. NERC will develop and facilitate data collection necessary to perform future analysis of substation equipment failures, as recommended by the ACSETF."*	Complete	For circuit breaker failures, Event Analysis is assessing the effectiveness of the alert. For all other items noted, the ACSETF presented a prioritized list of recommendations at the March 2015 Planning Committee meeting and a plan to address those recommendations will be developed in 2015, including necessary data collection. Actions recommended were assigned by the PC to the appropriate work groups. The ACSETF was disbanded.

Table 7.1: Completed Key Finding Actions							
Item Reference	**Finding Report Year**	**Key Finding Type**	**Key Finding Heading**	**Key Finding Reference**	**Key Finding Words**	**Key Finding Status**	**Actions Taken to Date**
18	2014	Metric Assessment	Use of Energy Emergency Alert Level 3 Declines	Page 19 Paragraph 4	*"In 2013 there were seven Energy Emergency Alert (EEA) Level 3 events declared, which is significantly lower than the number that occurred in prior years. Recommendation: NERC will analyze system events that resulted in firm load shedding to determine any common causes or trends that warrant action."*	Complete	This metric will continue to be monitored for the value in evaluating the reliability of the system. Modifications to the metric were made to ensure a comprehensive understanding of the use and occurrence of EEAs. Based upon continued analysis, there is an apparent improvement trend for this metric, as discussed in Chapters 2 and 4.

Table 7.2: Ongoing Key Finding Actions							
Item Reference	Finding Report Year	Key Finding Type	Key Finding Heading	Key Finding Reference	Key Finding Words	Key Finding Status	Actions Taken to Date
1	2012	Generation Performance	Resource Mix Changes Necessitate New Metrics	Page 11 Paragraph 1	"Resources such as wind generation and demand response are the non-traditional resources that perform differently than conventional generators. New metrics should be developed in order to determine what, if any, impact these differences have on reliability."	Ongoing	The wind data reporting instruction (Section 1600 Data Request for Wind Characteristics) will collect elementary performance data intended to enable the development of metrics. Demand response metrics have been developed but are being modified and aligned across all Regions so that consistent measurements can be calculated.
2	2013	Transmission Performance	Automatic Transmission Events with Unknown Cause Necessitate Analysis	Page 17 Paragraph 1	"Initiating [unknown] cause codes comprise 19 percent of all events with automatic outages. This may be an area where more analysis is needed."	Ongoing	Improvements have been made in unknown sustained cause codes by focused efforts by operators, Regional Entities and NERC. Work still remains for the TADSWG.
3		Metric Assessment	Severity Risk Index Assessment	Page 28 Paragraph 3	"Additionally, it appears that with the modified method of calculating SRI_{bps}, generation severity plays a substantial role in the daily summary values as measured by SRI_{bps}. Future state of reliability reports will contain information assembled and analyzed from GADS, which is likely to bring greater understanding to these facilities and their role assessing the reliability of the BPS. Further analysis of generation performance, particularly as it relates to daily bulk power system performance is appropriate; additional analysis will be incorporated into SOR reports in the future."	Ongoing	Generation loss was noted as a significant contributor to daily SRI. It will be subsequently reported within the annual state of reliability reports.
4	2011	Generation Performance	Generating Availability Performance	Page 3 Paragraph 3	"In the last three years, the Equivalent Forced Outage Rate - Demand (EFORd) increased, indicating a higher risk that a unit may not be available...Detailed analysis is needed to identify the root causes of increasing forced outage rate."	Ongoing	GADSWG analysis is underway and preliminary results are presented in this report. Work still remains for the GADSWG.

Chapter 8 – Spare Equipment Initiatives

Background

In June 2010, NERC issued a report titled *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*.[69] In a postulated high-impact low-frequency (HILF) event, such as a coordinated physical or cyber attack or a severe geomagnetic disturbance (GMD), long-lead-time[70] electric transmission system equipment may be damaged. This could adversely impact system reliability.

Following a HILF event, increased industry and government coordination will help maximize the use of available spare transmission equipment in restoring the grid, thereby increasing the resiliency of the system.

Following the aforementioned HILF report, the Spare Equipment Database Task Force (SEDTF) was created to update NERC's existing spare equipment database. The objective was provide an automated system with enhanced information security and usability for the industry to locate spare equipment in the event of an emergency or other non-routine failure. The SEDTF provided NERC staff with guidance on how the new system should operate and the NERC Spare Equipment Database (SED)[71] was developed. Following the development of the SED, the SEDTF became the Spare Equipment Database Working Group (SEDWG), with the purpose of conducting outreach and maintenance on the database.

In September 2014, the SEDWG's scope was updated to reflect the broader landscape of spare equipment and was renamed the Spare Equipment Working Group (SEWG).[72] The SEWG will continue to oversee the SED, but also assess the industry's posture on long-lead-time electric transmission equipment and act as a conduit for information exchange between the industry and government on the issue of spare equipment.

Spare Equipment and NERC Reliability Standards

Physical Security Standard CIP-014-1[73]

On November 20, 2014, FERC issued its final rule, largely approving CIP-014-1. CIP-014-1 focuses on critical facilities such as transmission stations or substations and their associated primary control centers that, if rendered inoperable or damaged, could have a critical impact on the operation of the interconnection through instability, uncontrolled separation, or cascading failures on the BPS. Requirement 5.5.1 of CIP-014-1 specifies an attribute for an entity's plan:

The physical security plan(s) shall include resiliency or security measures to deter, detect, delay, assess, communicate and respond to potential threats.

Having the ability to quickly locate available spare transformers is an important function of expanding BES resilience.

Transmission Planning Standard TPL-001-4[74]

The importance of spare transformers has also been identified in Requirement 2.1.5 of TPL-001-4, since they are a type of long-lead-time equipment:

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[69] *High Impact, Low Frequency Event Risk to the North American Bulk Power System*, June 2010, http://www.nerc.com/pa/ci/resources/documents/hilf_report.pdf.

[70] "Long lead time" is defined as six months or more.

[71] http://www.nerc.com/comm/PC/Spare Equipment Database Task Force SEDTF DL/SEDTF_Special_Report_October_2011.pdf.

[72] SEWG Scope, http://www.nerc.com/comm/PC/Spare Equipment Database Task Force SEDTF 2013/SEWG_scope_09_16_2014.pdf.

[73] Physical Security Standard, http://www.nerc.com/pa/Stand/Reliability Standards/CIP-014-1.pdf.

[74] TPL standard, http://www.nerc.com/files/TPL-001-4.pdf.

When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

Spare Equipment Working Group (SEWG)

Purpose of SEWG

The purpose of the Spare Equipment Working Group (SEWG) is to oversee the collection of information on long-lead-time electric transmission system equipment, assess the industry's posture on this equipment, and act as a conduit for information exchange between the industry and government on the issue of spare equipment.

SEWG Activities

In 2014, the primary focus of the SEWG was to increase participation. The SEWG worked with NERC and industry associations to host webinars and make presentations to explain the program to registered entities and to solicit new participants. In 2015, the SEWG will continue to increase SED awareness and participation, work on methods to gauge and assess the success and goals for the SED, and develop a white paper on the industry's posture on long-lead-time electric transmission equipment.

Spare Equipment Initiatives

NERC and industry are employing various initiatives with respect to spare equipment. Some of them are listed below.

Spare Equipment Database[75]

The NERC SED is able to support entities in search of spare power transformers available for purchase from other non-affiliated entities. If a HILF event such as a terrorist attack or natural disaster were to occur, the SED provides entities in need of multiple transformers the ability to connect with entities that have spare transformers available. Providing information to the database is voluntary and meant to complement existing transformer sharing and mutual assistance agreements. The database is populated and managed by participating organizations bound by a mutual confidentiality agreement.

SEWG reviewed various types of long-lead-time equipment. Following the review, it was determined that the initial focus should be large power transformers and generator step-up (GSU) transformers. In addition to long lead times, large power transformers also require substantial capital to secure. For these reasons, owners typically maintain an appropriate limited number of spares in the event of a failure. It may be beneficial in the future to expand the SED to include other types of long-lead-time equipment.

Confidentiality has been and continues to be an important aspect of the SED. Participating organizations voluntarily identify and report spare equipment that meets predefined criteria in the database. The data collected provides essential information to enable automated queries of available equipment. In addition, equipment owner information is required to facilitate communication following a HILF event.

SED utilizes a double-blind approach to preserve the anonymity of the registered SED participants, the requestor, and the owner of the equipment. To initiate the search, the requestor completes an online form and the program conducts a search. Upon completion, the requestor and the NERC SED administrator are notified of the success of the search. From there, the SED program initiates a double-blind search-response procedure. SED generates

[75] For further information related to the SED program, please visit: http://www.nerc.com/pa/RAPA/sed/Pages/Spare-Equipment-Database-(SED).aspx

messages to each unnamed TO identified by the search (without disclosing what equipment is needed, how many pieces of equipment are requested, or the name of the requestor).

Owners who wish to proceed with discussing a sale/lease/exchange can use the double-blind search process to respond to the unnamed requestor to open an active discussion. Any decision to provide additional information is the responsibility of the owners. The NERC SED administrator is informed of all communications conducted via the SED link. The requestor and owner may then work toward a settlement acceptable to both parties. A complete description of the SED search process and a special report on the SED can be found on NERC's website.[76]

Spare Transformer Equipment Program[77]

The Spare Transformer Equipment Program (STEP) was developed by industry through EEI in response to an industry-wide desire to cost-effectively increase reliability, particularly in the event of deliberate destruction of electrical transformers in connection with a terrorist event. The STEP program was designed to benefit the BPS by making certain that sufficient spare transformer capacity is available to allow an affected participating utility to restore its system following a triggering event to an N-0 reliability level. It does not, however, directly address routine failures or events that may cause specific, localized outages in distribution service to any particular facility. Although a triggering event is limited to an act of terrorism, the STEP program provides a ready mechanism for participating utilities to voluntarily share assets in the event of other catastrophic loss. There are currently 55 member utilities in the program.

SpareConnect[78]

SpareConnect is a mechanism for BPS asset owners and operators to network with other SpareConnect participants concerning the possible sharing of transmission and GSU transformers and related equipment, including bushings, fans, and auxiliary components. SpareConnect establishes a confidential, united platform for the entire electric industry to communicate equipment needs in the event of an emergency or other non-routine failure. SpareConnect complements existing programs, such as STEP and voluntary mutual assistance programs, by establishing an additional trusted network of participants who are uniquely capable of providing assistance concerning equipment availability and technical resources.

SpareConnect does not create or manage a central database of spare equipment. Instead, the program provides decentralized access to points of contact at electric industry companies so that, in the event of an emergency, SpareConnect participants are able to connect quickly with other participants in a selected voltage class.

SpareConnect does not impose any obligation on participants to provide any information or to make any particular piece of equipment available. Once connected, those SpareConnect participants who are interested in providing additional information or sharing equipment work directly and privately with each other on the specific terms and conditions of any potential equipment sale or other transaction.

[76] *Special Report: Spare Equipment Database System*, October 2011, http://www.nerc.com/docs/pc/sedtf/SEDTF_Special_Report_October_2011.pdf

[77] For more information about STEP, see http://www.eei.org/issuesandpolicy/transmission/Pages/sparetransformers.aspx.

[78] For more information about SpareConnect, contact: info@spareconnect.com.

Chapter 9 – BES Security Metrics

Background

The *State of Reliability 2014* report noted that the NERC PAS was collaborating with the BESSMWG to develop security performance metrics. During 2014, the BESSMWG developed an initial set of five metrics that have been approved by NERC's Critical Infrastructure Protection Committee (CIPC), with an additional two undergoing further development. This chapter introduces these new cyber and physical security metrics, provides results based on preliminary data collected during 2014, and proposes next steps to further refine these metrics, validate the results, and develop additional metrics.

Purpose

For some years now, NERC and the electricity industry have taken actions to address cyber and physical security risks to the BES as a result of potential and real threats, vulnerabilities, and events. CIPC established the BESSMWG to develop a comprehensive set of security performance metrics. These metrics would complement other NERC reliability performance metrics by defining lagging and leading indicators for security performance as they relate to reliable BES operation.

Methodology

The BESSMWG, composed of subject matter experts from NERC's Electricity Sector Information Sharing and Analysis Center (ES-ISAC) and experts from the electricity sector who have experience in physical security, cybersecurity, and power system operations, began their work by sharing how they measure and manage security performance within their own organizations. Members discussed the processes used to manage their security programs, as well as their own experiences with real security incidents and their potential impact on the BES. Through these discussions, members considered the available sources of data that might be helpful for improving security performance for the electricity sector as a whole. They also discussed the relative merits of lagging and leading indicators with the goal of developing metrics that address both attributes.

Lagging Indicators are results-oriented, measure historical events, and tend to be easier to measure.
Leading Indicators contribute to or precede events and tend to be more difficult to measure.

The BESSMWG identified the following challenges related to developing security performance metrics:

- **Limited Historical Data:** To date, there have been relatively few security incidents with the potential to affect the BES. Physical security incidents, such as vandalism and sabotage, have occurred infrequently for decades, typically with little or no impact on BES reliability. However, recent high-profile events have increased awareness regarding the potential for physical security incidents to significantly impact the BES. Risks associated with cybersecurity appear to be rapidly evolving as the nature of cyber intrusions becomes increasingly sophisticated.
- **Limited Ability to Normalize Available Data:** Ideally, metrics provide a proportional indication by statistically sampling a known fraction of the whole, instead of measuring all events. Security threats and vulnerabilities are constantly changing. Therefore, security performance metrics are limited to absolute numbers rather than statistically valid percentages of the whole. While absolute numbers may indicate trends, work must continue to normalize available data to further refine this metric.
- **Changing Threat Landscape:** The frequency of physical and cybersecurity threats, vulnerabilities, and incidents, while historically low, is changing rapidly. Adversaries are becoming increasingly sophisticated in using malware to pursue targets.

- **Sensitive Information:** Information that details security threats, vulnerabilities, and real incidents is highly sensitive. In the wrong hands, this information can expose existing vulnerabilities to new and sophisticated exploits, create additional vulnerabilities, and limit effective response.

NERC Reliability Principles

NERC's Reliability Principles were developed to help ensure NERC's Reliability Standards are developed in a consistent manner to support the reliability of the BES. While the development of security performance metrics is not limited to the scope of NERC's Reliability Standards, the eighth principle is relevant.

> *8. Bulk power systems shall be protected from malicious physical or cyber attacks.*

Assessing the Value of the Metrics

To assess the relative value of the security metrics being considered, the BESSMWG used the same SMART[79] rating criteria used for developing the reliability performance metrics. As the SMART criteria were developed specific to BES reliability, the BESSMWG found the criteria helped ensure that the impact of security on the reliability of the BES was kept foremost in mind. From that perspective, security metrics that did not have an apparent link to BES reliability received a lower SMART rating score, while those that have an apparent link received a higher score.

The BESSMWG considered several general categories related to security performance:

- **Actual Physical and Cyber Events:** NERC's Reliability Standards require entities to report cyber and physical security incidents or events according to certain criteria. The BESSMWG considered metrics that would summarize these historical events as lagging indicators of security performance. Of importance is not just the number and frequency of these events over time, but also the extent to which they may have resulted in a loss of load to customers.
- **Information Sharing:** The ability of entities to quickly and effectively share information with each other is an important capability when responding to new or rapidly evolving emergency situations. NERC's ES-ISAC provides a central clearing house to receive, analyze, and share information with member entities. The BESSMWG considered metrics that would provide leading indicators of the extent to which entities are actively engaged with the ES-ISAC on a macro level.
- **Global Cyber Vulnerabilities:** Cybersecurity is not a concern limited to the electricity sector. The BESSMWG considered publicly available metrics that describe how cyber vulnerabilities at the global level affecting all information technologies are changing over time. While these metrics do not provide a direct measure of the impact on the BES, they may provide leading indicators relevant to the electricity sector.

The BESSMWG considered an initial set of more than 20 security performance metrics. Detailed definitions have been developed for the top five of these metrics based on available data. An additional two are being considered for further development during 2015. All security performance metrics are reported on an aggregated basis at the North American level, as there is no evidence to suggest that details at the interconnection or Regional Entity levels would be meaningful.

[79] SMART: Specific/Simple, Measurable, Attainable, Relevant, and Tangible/Timely.

Security Performance Metrics and Preliminary Results

This section provides the five security performance metrics approved by CIPC for implementation.

BES Security Metric 1: Reportable Cyber Security Incidents

This metric reports the total number of Reportable Cyber Security Incidents[80] that occur over time and identifies how many of these incidents have resulted in a loss of load. It is important to note that any loss of load will be counted, regardless of direct cause. For example, if load was shed as a result of a loss of situation awareness caused by a cyber incident affecting an entity's energy management system, the incident would be counted even though the cyber incident did not directly cause the loss of load (e.g., through an unauthorized breaker operation). This metric will provide an indication of the number of Reportable Cyber Security Incidents and the resilience of the BES to operate reliably and continue to serve load.

This metric is based on data reported by entities, as required by Reliability Standard CIP-008-3, to NERC's ES-ISAC, where it is analyzed. Data for this metric is provided in Table 9.1. Given the current relatively low number of such incidents, it is anticipated that the data will be gathered and summarized quarterly. Analysis of this security performance metric data shows that no Reportable Cyber Security Incident resulted in loss of load on the BPS in 2014.

Preliminary Results Based on Data Collected During 2014

Table 9.1: Reportable Cyber Security Incidents

Metric	2014				2015				2016			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Total number of Reportable Cyber Security Incidents	3											
Total number of Reportable Cyber Security Incidents resulting in loss of load	0											

BES Security Metric 2: Reportable Physical Security Events

This metric reports the total number of physical security reportable events[81] that occur over time and identifies how many of these events have resulted in a loss of load. It is important to note that any loss of load will be counted, regardless of direct cause. For example, if load was shed as a result of safety concerns due to a break-in at a substation, the event would be counted even though no equipment was damaged to directly cause the loss of load. The metric will provide an indication of the number of physical security reportable events and the resilience of the BES to operate reliably and continue to serve load.

This metric is based on data reported by entities as required by Reliability Standard EOP-004-2to NERC's Bulk Power System Awareness group, which is then analyzed by NERC's ES-ISAC. Data for this metric is provided in Table 9.2. Given the current relatively low frequency of such incidents, it is anticipated that the data will be gathered and summarized quarterly. Analysis of this security performance metric data showed that no physical security reportable event resulted in loss of load on the BPS in 2014.

[80] Ref. NERC Glossary of Terms: "A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity."

[81] Reportable Events are defined in Reliability Standard EOP-004-2 Event Reporting, Attachment 1.

Preliminary Results Based on Data Collected During 2014

Table 9.2: Reportable Physical Security Events												
Metric	2014				2015				2016			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Total number of reportable events as a result of physical security threats to a Facility or BES control center	47											
Total number of reportable events that caused physical damage or destruction to a Facility	9											
Total number of reportable events as a result of physical security threats to a Facility or BES control center, or that caused physical damage or destruction to a Facility, that resulted in a loss of load	0											

BES Security Metric 3: ES-ISAC Membership

This metric reports the total number of electricity sector organizations and individuals registered as members of the ES-ISAC. ES-ISAC member organizations include NERC registered entities and others in the electricity sector. Given today's rapidly changing threat environment, it is important that electricity entities be able to quickly receive and share security-related information. This metric provides the number of organizations registered, as well as the number of individuals. Increasing ES-ISAC membership should serve to collectively increase awareness of security threats and vulnerabilities and enhance the sector's ability to respond quickly and effectively.

This metric is based on data available from the ES-ISAC. Data for this metric is provided in Table 9.3. It is anticipated that the data will be gathered and summarized quarterly. The data shows that registered membership of the ES-ISAC is increasing every quarter.

Preliminary Results Based on Data Collected During 2014

Table 9.3: ES-ISAC Membership												
Metric	2014				2015				2016			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Total number of electricity sector organizations registered as members of the ES-ISAC	496	557	578	827								
Total number of individuals in ES-ISAC member organizations who have ES-ISAC accounts	1514	1844	2010	2770								

BES Security Metric 4: Industry-Sourced Information Sharing

This metric reports the total number of Incident Bulletins published by the ES-ISAC based on information voluntarily submitted by ES-ISAC member organizations. ES-ISAC member organizations include NERC registered entities and others in the electricity sector. Incident Bulletins describe cyber and physical security incidents and provide timely, relevant, and actionable information of broad interest to the electricity sector. But given security issues, they do not represent the complete picture of physical and cyber information available to or distributed by the ES-ISAC.

This metric is based on data reported to and analyzed by the ES-ISAC. Data for this metric is provided in Table 9.4. Given the current relatively low frequency of such incidents, it is anticipated that the metric data will be gathered and summarized quarterly.

Preliminary Results Based on Data Collected During 2014

Table 9.4: Industry-Sourced Information Sharing

Metric	2014				2015				2016			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Total number of ES-ISAC Incident Bulletins based on information provided by the electricity sector	18	26	22	14								

BES Security Metric 5: Global Cyber Vulnerabilities

This metric reports the number of global cybersecurity vulnerabilities that are considered to be high severity. This metric is based on data published by the National Institute of Standards and Technology (NIST). NIST defines high-severity vulnerabilities as those with a common vulnerability scoring system[82] (CVSS) of seven or higher. As the term "global" implies, this metric is not limited to information technology typically used by electricity sector entities. As a result, this metric received a relatively low score using the SMART rating criteria. However, the BESSMWG recommends that this metric be adopted as it provides a leading indicator of the extent of constantly evolving cyber vulnerabilities and identifies trends beyond the electricity sector that may be relevant to the sector. Data for this metric is provided in Table 9.5. The data will be gathered and summarized quarterly.

Preliminary Results Based on Data Collected During 2014

Table 9.5: Global Cyber Vulnerabilities

Metric	2014				2015				2016			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Number of global cyber vulnerabilities considered to be high severity	446	499	418	557								

[82] Ref. NIST http://nvd.nist.gov/cvss.cfm.

Next Steps

The BESSMWG acknowledges that these five metrics represent only the first step in developing meaningful security performance metrics on behalf of the electricity industry. Through 2015, the BESSMWG will work with the ES-ISAC to help validate the data for these five metrics and continue to define additional metrics that can be developed with readily available data. In addition, the BESSMWG will develop a longer-term roadmap to explore other metrics that would be valuable, regardless of the extent to which the data is currently readily available.

Appendix A – Statistical Analysis for Risk Issue Identification and Transmission Outage Severity Analysis

Study Method

Defining BPS Impact from Transmission Risk

The SRI presented in Chapter 2 consists of several weighted risk impact components: generation, transmission, and load loss.[83] The transmission outage impact component of the SRI is defined as $w_T \times N_T$, where w_T is a weighting factor of 30 percent and N_T is the severity impact of a given day's transmission outages on the BPS based on TADS outages. Since transmission outages are a significant contributor to the overall SRI, this appendix provides an analysis of the individual TADS events based on TADS outage ICCs.

Equation A.1 is used to calculate the transmission outage severity component of a TADS event. The severity of a transmission outage is calculated based on its assumed contribution of power flow through transmission circuits. The average power flow MVA values, or Equivalent MVA Values, used in Equation A.1, are shown in Table A.1. These Equivalent MVA Values are also applied to the denominator of the transmission outage severity equation to normalize the function. The TADS event severity is then analyzed by ICC to investigate relative information between the ICCs.

For normalization, the total number of transmission circuits from the same year as the event is multiplied by each voltage class's Equivalent MVA value. For example, if an outage occurred in 2014, the normalization would use the total number of transmission circuits in 2014. This allows comparison of TADS events across years while taking into account the changing number of circuits within the BPS.

$$Transmission\ Severity\ (TADS\ event) = \left[\frac{\sum_{AC\ circuit\ Outages\ in\ Event}(Equivalent\ MVA)}{\sum_{AC\ circuit\ Inventory\ Counts}(Equivalent\ MVA)}\right] \cdot 1000$$

Equation A.1

Table A.1: Transmission Outage Severity Equivalent MVA Values

Voltage Class	Equivalent MVA Value
200–299 kV	700
300–399 kV	1300
400–599 kV	2000
600–799 kV	3000

In these studies, TADS events associated with automatic (forced) ac circuit outages that occurred from 2012 to 2014 are analyzed. Four data sets of TADS events studied separately are described further in Appendix A:

- All TADS events
- Common and Dependent Mode events
- Sustained events
- TADS events by Region

[83] http://www.nerc.com/docs/pc/rmwg/pas/index_team/sri_equation_refinement_may6_2011.pdf, pp. 2-3.

Determining Initiating Causes and Modification Method

TADS events are categorized by ICCs.[84] These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity. The procedure illustrated in Figure A.1 is used to determine a TADS event's ICC. The procedure that defines ICCs for a TADS event allows ICC assignment to a majority of transmission outage events recorded in TADS.

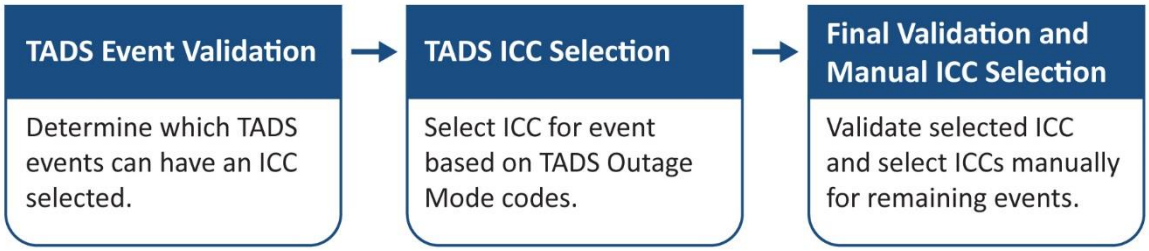

Figure A.1: TADS Event Initiating Cause Code Selection Procedure

Previous state of reliability reports have analyzed the TADS data set and its ICCs. The 2013 and 2014 *State of Reliability* reports also included analysis based on an augmented data set that defined changes in ICCs to further distinguish normal clearing events from abnormal clearing events. Two TADS ICCs are impacted: Human Error and Failed Protection System Equipment.

- TADS Human Error ICC is subdivided by type codes, which first became available in 2012. For the purpose of the state of reliability, data for two specific type codes related to protection system misoperation have been removed from the Human Error ICC and added to the Failed Protection System Equipment ICC. Those type codes are 61 dependability[85] (failure to operate) and 62 security[86] (unintended operation).

- TADS Failed Protection System Equipment ICC plus the Human Error type code 61 and 62 data are added together in a new or augmented ICC labeled "Misoperation" in each state of reliability report.

The 2013 and 2014 *State of Reliability* reports have revealed that analyzing data based on both data sets (TADS ICCs and TADS augmented ICCs to include the Misoperation cause code) has not provided additional information. Therefore, starting with this report, the data and analysis in this appendix will be based on the augmented ICC data set, which currently contains three years of data. In future years, the analysis will be based on the most recent five years of augmented ICC data.

In this report, references to ICC mean the augmented ICC as described above.

Event Statistics by Year

There are 10,748 TADS events with ICCs assigned, comprising 99.6 percent of the total number of TADS events for the years 2012 to 2014. These events contribute 99.1 percent of the total calculated transmission outage severity of the database. Table A.2 provides the corresponding event statistics by year.

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[84] For detailed definitions of TADS cause codes, please refer to: http://www.nerc.com/pa/RAPA/tads/Transmission Availability Data System Working Group/TADS Definitions (Appendix 7).pdf, January 14, 2013, pp. 19-20.

[85] Event Type 61 Dependability (failure to operate): one or more automatic outages with delayed fault clearing due to failure of a single protection system (primary or secondary backup) under either of these conditions:
- Failure to initiate the isolation of a faulted power system Element as designed, or within its designed operating time, or
- In the absence of a fault, failure to operate as intended within its designed operating time.

[86] Event Type 62 Security (unintended operation): one or more automatic outages caused by improper operation (e.g., overtrip) of a protection system resulting in isolating one or more TADS elements it is not intended to isolate, either during a fault or in the absence of a fault.

Table A.2: TADS Outage Events Summary (2012–2014)				
Summary	**2012**	**2013**	**2014**	**2012–2014**
Number of TADS events	3,753	3,557	3,477	10787
Number of events with ICC assigned	3,724	3,557	3,467	10748
Percentage of events with ICC assigned	99.2%	100.0%	99.7%	99.6%
Transmission outage severity all TADS events	612.4	506.0	448.2	1566.6
Transmission outage severity of TADS events with ICC assigned	602.1	506.0	445.0	1553.1
Percentage of Transmission outage severity of events with TADS ICC assigned	98.3%	100.0%	99.3%	99.1%

In particular, the statistics in Table A.2 show that, on average, one transmission event occurs in North America every 2 hours and 26 minutes.

Events with Common ICC by Year and Estimates of Event Probability

Table A.3 lists annual counts and hourly event probability of TADS events by ICC. The ICCs with the largest number of events are weather (with and without lightning), Unknown, Misoperation, Failed AC Circuit Equipment, and Failed AC Substation Equipment. These groups together amount to 76 percent of TADS events for three years.

Almost all TADS ICC groups have sufficient data available to be used in a statistical analysis. Only three ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; and Environmental) do not have enough observations for reliable statistical inferences. These are combined into a new group, named "Combined Smaller ICC Groups," that can be statistically compared to every other group and also studied with respect to annual changes of transmission outage severity.

With the development of the transmission outage severity measure and TADS event ICCs, it is possible to statistically analyze the most recent three years of TADS data (2012–2014). For TADS events initiated by a common cause, the probability[87] of observing the initiation of an event during a given hour is estimated using the corresponding historical event occurrences reported in TADS. Namely, the event occurrence probability is the total number of occurrences for a given type of event observed during the historical data period divided by the total number of hours in the same period. Therefore, the sum of the estimated probabilities for all events is equal to the estimated probability of any event during a given hour.

[87] Probability is estimated using event occurrence frequency of each ICC type without taking into account the event duration.

Table A.3: TADS Events and Hourly Event Probability by ICC (2012–2014)					
Initiating Cause Code	**2012**	**2013**	**2014**	**2012–2014**	**Event Initiation Probability/Hour**
Lightning	852	813	709	2374	0.090
Unknown	710	712	779	2201	0.084
Weather, excluding lightning	446	433	441	1320	0.050
Misoperation	321	281	314	916	0.035
Failed AC Circuit Equipment	261	248	224	733	0.028
Failed AC Substation Equipment	248	191	223	662	0.025
Foreign Interference	170	181	226	577	0.022
Human Error (w/o Type 61 OR Type 62)	212	191	149	552	0.021
Contamination	160	151	149	460	0.017
Fire	106	130	44	280	0.011
Power System Condition	77	109	83	269	0.010
Other	104	64	77	245	0.009
Combined Smaller ICC groups	57	53	49	159	0.006
Vegetation	43	36	39	118	0.004
Vandalism, Terrorism, or Malicious Acts	10	9	8	27	0.001
Environmental	4	8	2	14	0.001
All with ICC assigned	3724	3557	3467	10748	0.409
All TADS Events	3753	3557	3477	10787	0.410

Determining Relative Risk

The process of the statistical analysis performed to identify top causes to transmission risk is demonstrated in Figure A.2. After Step 1 (quantifying an event impact by transmission outage severity) and Step 2 (assigning initiating causes to TADS events), at Step 3, NERC staff determined the correlation between each ICC and transmission outage severity and detected statistically significant relationships between several initiating causes and transmission outage severity. Also, sample distributions were studied to determine any statistically significant pair-wise differences in expected transmission outage severity between ICCs, including a time trend analysis where applicable. Finally, at Step 4, the relative risk was calculated for each ICC group, and initiating causes were ranked by their risk to the transmission system.

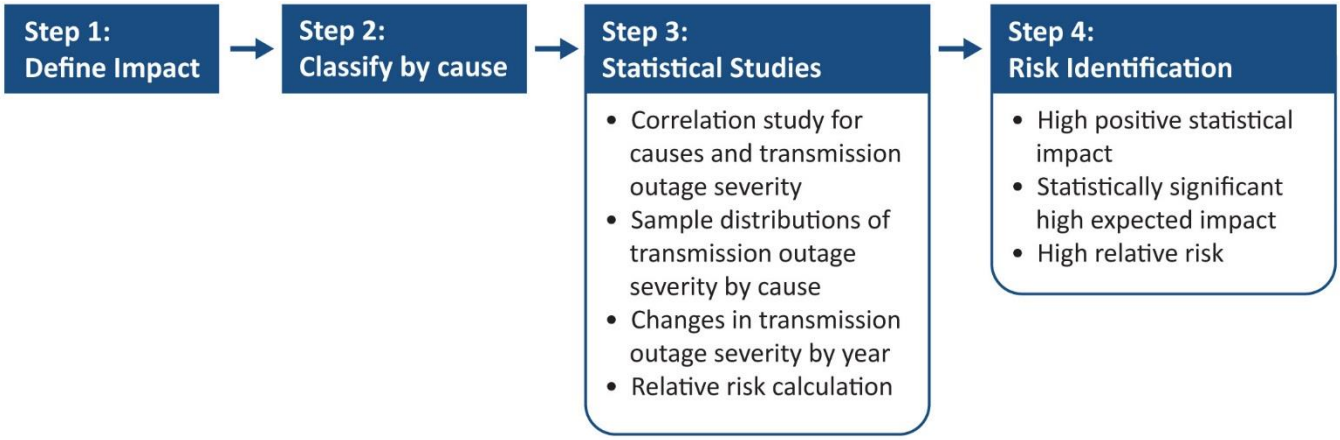


Figure A.2: Risk Identification Method

To study the relationship between ICCs and the transmission outage severity of TADS events, NERC investigated the statistical significance of the correlation between transmission outage severity and the indicator function[88] of a given ICC.[89] The test is able to determine a statistically significant positive or negative correlation between ICC and transmission outage severity.

Distributions of transmission outage severity for the entire dataset were examined separately for events with a given ICC. A series of t-tests[90] were performed to compare the expected transmission outage severity of a given ICC with the expected outage severity of the rest of the events at significance level of 0.05. Then, the Fisher's Least Square[91] difference method was applied to determine statistically significant[92] differences in the expected transmission outage severity for all pairs of ICCs.

Where applicable, the time trend analysis was performed. Statistically significant differences in the expected transmission outage severity for each ICC group were analyzed for each year of data. This showed if the average transmission outage severity for a given ICC group had changed over time.

[88] The indicator function of a given ICC assigns value 1 to an event with this ICC and value 0 to the rest of the events.

[89] For each ICC, a null statistical hypothesis on zero correlation at significance level 0.05 was tested. If the test resulted in rejection of the hypothesis, it is concluded that a statistically significant positive or negative correlation between an ICC and transmission severity exists; the failure to reject the null hypothesis indicates no significant correlation between ICC and transmission severity.

[90] For t-test, see D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 361-369.

[91] For Fisher's Least Significance Difference (LSD) method or test, see D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 524-526.

[92] At significance level of 0.05.

Finally, relative risk was calculated for each ICC group. The impact of an outage event was defined as the expected transmission outage severity associated with a particular ICC group. The probability that an event from a given group initiates during a given hour is estimated from the frequency of the events of each type without taking into account the event duration. The risk per hour of a given ICC was calculated as the product of the probability per hour and the expected severity (impact) of an event from this group. The relative risk was then defined as the percentage of the risk associated with each ICC out of the total (combined for all ICC events) risk per hour. Finally, risk profiles of TADS events initiated by common causes are visualized as bubble charts that summarize results of correlational, distributional, and risk ranking analyses.

Correlation between ICC and Transmission Outage Severity

To study a relationship between ICC and transmission outage severity of TADS events, the statistical significance of the correlation between transmission outage severity and the indicator function[93] of a given ICC was investigated.[94] A statistically significant positive or negative correlation between ICC and transmission outage severity could be determined by the statistical test. There were three key outcomes of all the tests. A statistically significant positive correlation of ICC to transmission outage severity indicates a greater likelihood that an event with this ICC would result in a higher transmission outage severity. A stark negative correlation indicates the contrary; in this case, a lower transmission outage severity would be likely. If no significant correlation is found, it indicates the absence of a linear relationship between ICC and the transmission outage severity, and that the events with this ICC have an expected transmission outage severity similar to all other events from the database.

Figure A.3 shows the correlations between calculated transmission outage severity and the given ICC. A red bar corresponds to an ICC with statistically significant positive correlation with transmission outage severity, a green bar corresponds to an ICC with statistically significant negative correlation, and a blue bar indicates no significant correlation. Thus, Misoperation, Failed AC Substation Equipment, and Power System Condition have statistically significant positive correlation with transmission outage severity. The expected severity of events with each of these ICCs is greater than the expected severity of other ICC events. Secondly, Weather Excluding Lightning, Foreign Interference, Unknown, and Combined Smaller ICC Groups have a statistically significant negative correlation with transmission outage severity. The expected severity of events initiated by these causes is less than the expected transmission outage severity of other TADS events. Finally, events with each of the ICCs with blue bars have the expected transmission outage severity similar to all other events in TADS.

[93] The indicator function of a given ICC assigns value 1 to an event with this ICC and value 0 to the rest of the events.

[94] For each ICC, a null statistical hypothesis on zero correlation at significance level 0.05 was tested. If the test resulted in rejection of the hypothesis, it is concluded that a statistically significant positive or negative correlation between an ICC and transmission outage severity exists; the failure to reject the null hypothesis indicates no significant correlation between ICC and transmission outage severity.

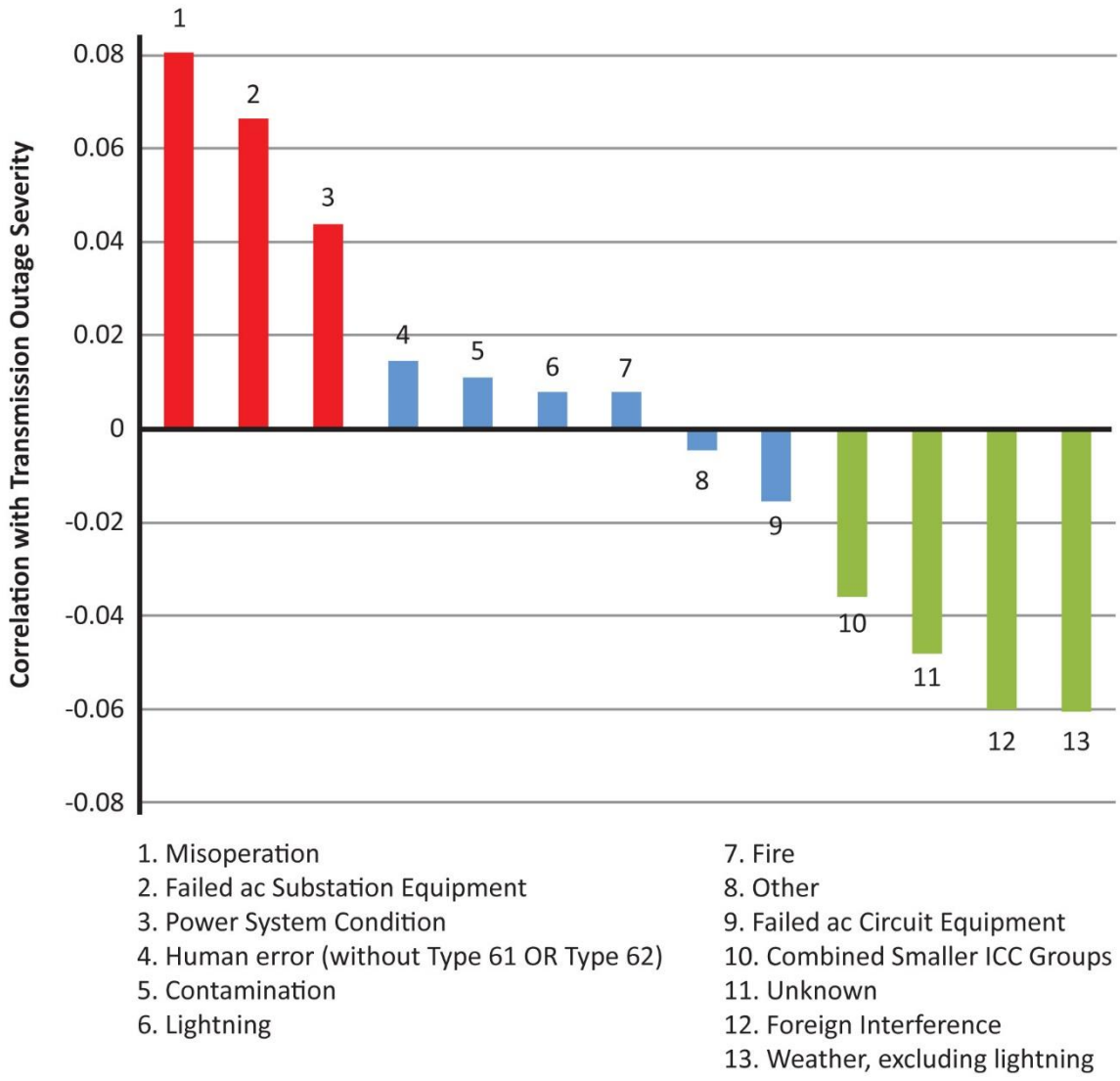


Figure A.3: Correlation between ICC and Transmission Outage Severity of TADS Events (2012–2014)

Distribution of Transmission Outage Severity by ICC

Next, the distribution of transmission outage severity for the dataset was studied separately for events with a given ICC and the complete dataset. The transmission outage severity of the 2012 to 2014 dataset has a sample mean of 0.15 and the sample standard deviation of 0.10. The sample statistics for transmission outage severity by ICC are listed in Table A.4, with the ICCs ordered from the largest average transmission outage severity to the smallest one.

A series of the Fisher's Least Square tests confirms that the groups of events initiated by Power System Condition, Misoperation, and Failed AC Substation Equipment have statistically[95] greater expected severity than other events, in accordance with the correlation analysis described above. It means that when an event initiated by one of these causes occurs, it has, on average, a greater impact and a higher risk to the transmission system. Moreover, the tests on homogeneity of variances point out to statistically greater variances (and the standard deviations) for

[95] At significance level 0.05

each of these groups as compared with other events. The greater variance is an additional risk factor since it implies more frequent occurrences of events with high transmission outage severity.

Table A.4 provides a column that lists ICCs that are statistically less than a given ICC referenced by the table's column 1 index. For example, Power System Condition, Misoperation, and Failed AC Substation Equipment initiate events with statistically larger transmission outage severity than any other ICC starting with Human Error. However, pairwise differences between three top groups are not significant, meaning that an individual impact of events from these groups is statistically less.

Table A.4: Distribution of Transmission Outage Severity by ICC (2012–2014)

#	Initiating Cause Code (ICC)	Average TS	Is Expected TS statistically significantly different than for other events?	ICC with statistically significantly smaller TS	Standard Deviation of TS
1	Power System Condition	0.1702	Larger	4,5,6,7,8,9,10,11,12,13	0.15
2	Misoperation	0.1693	Larger	4,5,6,7,8,9,10,11,12,13	0.14
3	Failed AC Substation Equipment	0.1689	Larger	4,5,6,7,8,9,10,11,12,13	0.12
4	Human Error (w/o Type 61 OR Type 62)	0.1527	No	9,10,11,12,13	0.10
5	Contamination	0.1493	No	10,11,12,13	0.08
6	Fire	0.1489	No	10,11,12,13	0.09
7	Lightning	0.1459	No	10,11,12,13	0.09
	All TADS events	**0.1452**	**N/A**	**N/A**	**0.10**
	All with ICC assigned	**0.1445**	**N/A**	**N/A**	**0.09**
8	Other	0.1417	No	12,13	0.10
9	Failed AC Circuit Equipment	0.1391	No	12,13	0.08
10	Unknown	0.1356	Smaller	12,13	0.07
11	Weather, excluding lightning	0.1334	Smaller	12,13	0.08
12	Foreign Interference	0.1207	Smaller	None	0.06
13	Combined Smaller ICC groups	0.1169	Smaller	None	0.06

Average Transmission Outage Severity by ICC: Annual Changes

Year-over-year changes in calculated transmission outage severity by ICC were reviewed next. Figure A.4 shows changes in the average transmission outage severity for each ICC for the 2012 to 2014 dataset. The groups of ICC events are listed from left to right by descending average transmission outage severity for the three years. The largest average transmission outage severity over the data period was observed for events initiated by Power System Condition.

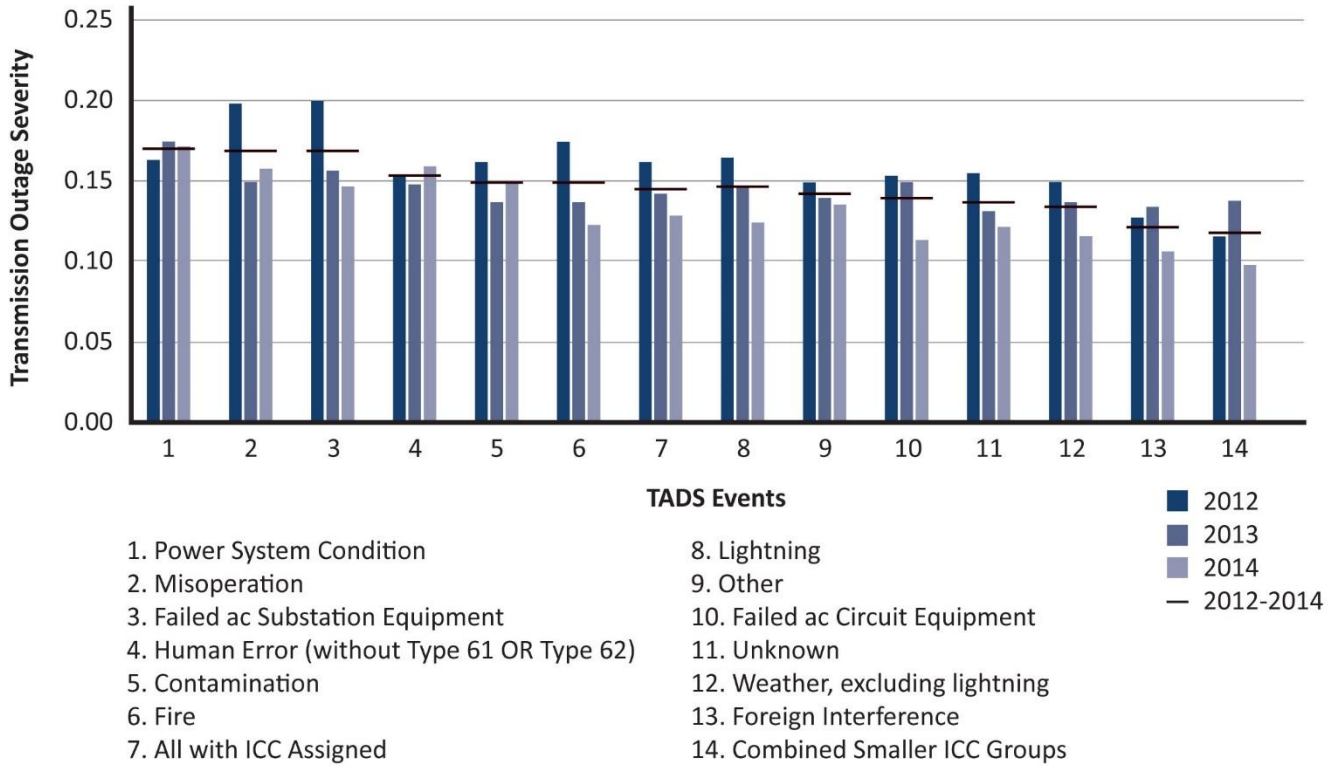


Figure A.4: Average Transmission Outage Severity of TADS Events by ICC (2012–2014)

It should be noted that Power System Condition ICC, which in the *State of Reliability 2014* report followed Failed AC Substation Equipment and Misoperations ICCs, moved to the top spot based on the three-year data. Power System Condition is defined as "Automatic Outages caused by power system conditions such as instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations (e.g., an abnormal terminal configuration due to existing condition with one breaker already out of service)." In Figure A.4, one can see that both Failed AC Substation Equipment and Misoperations ICCs have a large reduction in the average transmission outage severity from 2012 to 2013 and stayed essentially flat from 2013 to 2014. Statistical tests confirm that these decreases from 2012 to 2013 were statistically significant.[96] In contrast, the average transmission outage severity of events initiated by Power System Condition had no significant year-over-year changes over these three years.

Another important conclusion comes from the analysis of transmission outage severity of all TADS events with ICC assigned. Their average transmission outage severity significantly decreased from 2012 to 2013 and then again from 2013 to 2014. The same trend is observed for events with ICCs Lightning, Unknown, and Weather excluding Lightning—the three largest groups of TADS events.

[96] This summary only lists changes that are statistically significant at the 0.05 level.

Transmission Outage Severity Risk and Relative Risk of TADS Events by ICC

The risk of each ICC group can be defined as the total transmission outage severity associated with this group; its relative risk is equal to the percentage of the group transmission outage severity in the 2012 to 2014 database. Equivalently, the risk of a given ICC per hour can be defined as the product of the probability that an event with this ICC initiates during an hour and the expected severity (impact) of an event from this group. For any ICC group, the relative risk per hour is the same as the relative risk for a year (or any other time period) if estimated from the same dataset.

Relative risk of the 2012 to 2014 TADS events by ICC is listed in Table A.5. The probability that an event from a given group initiated during a given hour is estimated from the frequency of the events of each type without taking into account the event duration. Excluding weather-related events and events with Unknown ICC, events initiated by Misoperations and by Failed AC Substation Equipment had the largest shares in the total transmission outage severity and contributed 9.9 and 7.1 percent, respectively, to transmission outage severity relative risk.

Note that Power System Condition has a low rank despite having the largest average transmission outage severity of an individual event from this group. The reason is that there is a small number of events with this ICC and, therefore, rare occurrences of these events are reflected by their small probability.

Table A.5: Relative Risk by ICC (2012–2014)

Group of TADS events	Probability that an event from a group starts during a given hour	Expected Impact (expected transmission outage severity of an event)	Risk associated with a group per hour	Relative Risk by group
All TADS events	0.410	0.145	0.0596	**100.0%**
All with ICC assigned	0.409	0.144	0.0590	**99.1%**
Lightning	0.090	0.146	0.0132	**22.1%**
Unknown	0.084	0.136	0.0113	**19.1%**
Weather, excluding lightning	0.050	0.133	0.0067	**11.2%**
Misoperation	0.035	0.169	0.0059	**9.9%**
Failed AC Substation Equipment	0.025	0.169	0.0043	**7.1%**
Failed AC Circuit Equipment	0.028	0.139	0.0039	**6.5%**
Human Error (w/o Type 61 OR Type 62)	0.021	0.153	0.0032	**5.4%**
Foreign Interference	0.022	0.121	0.0026	**4.4%**
Contamination	0.017	0.149	0.0026	**4.4%**
Power System Condition	0.010	0.170	0.0017	**2.9%**
Fire	0.011	0.149	0.0016	**2.7%**
Other	0.009	0.142	0.0013	**2.2%**
Combined Smaller ICC groups	0.006	0.117	0.0007	**1.2%**

Figure A.5 shows year-over-year changes in the relative risk of TADS events by ICC. The groups of ICC events are listed from left to right by descending relative risk for the three years. The top-three contributors to transmission risk—Lightning, Unknown, and Weather excluding Lightning—had a statistically significant decrease in the expected outage severity, as described in the previous section. For ICC Lightning, the number of events in 2014 also decreased, and both decreases (in probability and an impact) resulted in a drop in the 2014 transmission risk. On the contrary, the number of events with ICC Unknown increased in 2014 and offset the expected severity decrease; thus, the transmission risk for ICC Unknown grew in 2014. Finally, for Weather excluding Lightning, increase in probability and decrease in expected severity compensated each other, and the transmission risk stayed flat.

For both Misoperation and Failed AC Substation Equipment ICCs, the number of events increased in 2014 and offset the statistically significant decrease in their expected transmission outage severity; this resulted in an increased transmission risk and increased relative risk for these two ICCs.

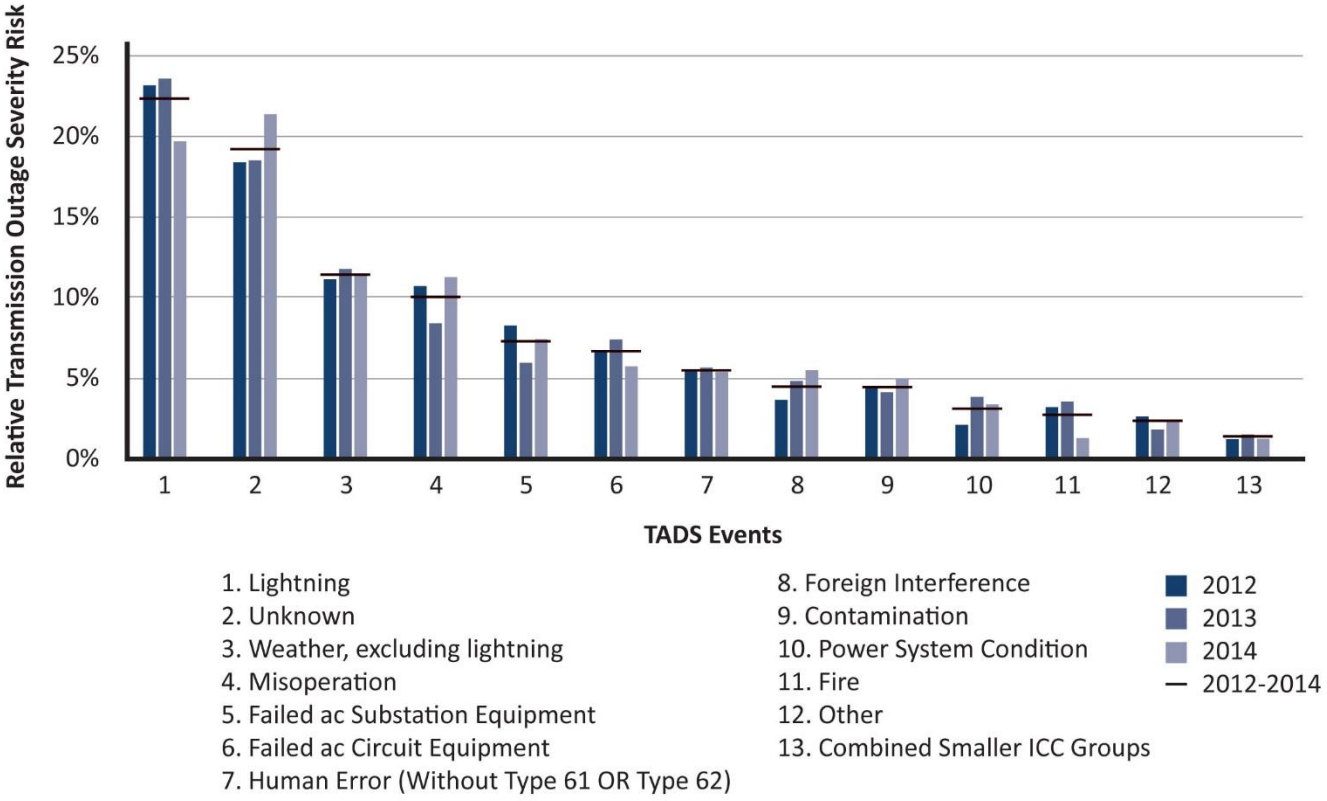


Figure A.5: Relative Transmission Outage Severity Risk by ICC and Year

Common/Dependent Mode Event ICC Study (2012–2014)

TADS also provides information to classify outages as single-mode or common or dependent mode (CDM) events that should be evaluated separately from single-mode events. CDM events result in multiple transmission element outages. It is important to monitor and understand CDM events due to their potential risk to system reliability. These TADS events have more transmission outage severity than TADS events with a Single Mode outage. A Single Mode event is defined as a TADS event with a single-element outage. A CDM TADS event is a TADS event where all outages have one of the modes (other than Single Mode) in Table A.6.

Based on this definition, every TADS event was categorized as either a Single Mode event or a CDM event. Some TADS events were entered as a combination of Single Mode outages and other outage modes. These events were manually examined to determine if the event was Single Mode or CDM. For some events, it was not possible to determine whether the event was Single Mode or CDM, nor was it possible to tell the ICC for the event. These events, approximately 0.3 percent of all TADS events, were removed from the study.

Table A.6: Outage Mode Codes

Outage Mode Code	Automatic Outage Description
Single Mode	A single-element outage that occurs independently of another automatic outage
Dependent Mode Initiating	A single-element outage that initiates at least one subsequent element automatic outage
Dependent Mode	An automatic outage of an element that occurred as a result of an initiating outage, whether the initiating outage was an element outage or a non-element outage
Common Mode	One of at least two automatic outages with the same initiating cause code where the outages are not consequences of each other and occur nearly simultaneously
Common Mode Initiating	A common-mode outage that initiates one or more subsequent automatic outages

Table A.7 lists CDM events by ICC in the 2012 to 2014 database and their percentages with respect to all TADS events with a given ICC. Note that the Misoperations ICC initiated the largest number of CDM events. CDM events initiated by Lightning comprise the second-largest group, followed by Failed AC Substation Equipment and Unknown. Overall, 1613 CDM events were defined. Out of these, 1576 are assigned to one of the 16 ICCs.

Table A.7: CDM Events and Hourly Event Probability by ICC (2012–2014)

Initiating Cause Code	ALL TADS events	CDM events	CDM as % of ALL	Event Initiation Probability/Hour
Misoperation	916	286	31.2%	0.0109
Lightning	2374	270	11.4%	0.0103
Failed AC Substation Equipment	662	225	34.0%	0.0086
Unknown	2201	137	6.2%	0.0052
Weather, excluding lightning	1320	123	9.3%	0.0047
Human Error (w/o Type 61 OR Type 62)	552	119	21.6%	0.0045
Power System Condition	269	118	43.9%	0.0045
Failed AC Circuit Equipment	733	99	13.5%	0.0038
Other	245	68	27.8%	0.0026
Foreign Interference	577	59	10.2%	0.0022
Fire	280	33	11.8%	0.0013
Contamination	460	23	5.0%	0.0009
Combined Smaller ICC groups	159	16	10.1%	0.0006
Vegetation	118	7	5.9%	0.0003
Environmental	14	6	42.9%	0.0002
Vandalism, Terrorism, or Malicious Acts	27	3	11.1%	0.0001
All with ICC assigned	10748	1576	14.7%	0.0599
All TADS events	10787	1613	15.0%	0.0613

CDM events are a subset of the previously evaluated TADS events; they comprise 15 percent of all TADS events from 2012 to 2014. Annual datasets of CDM events do not have enough observations to run statistical analyses and track statistically significant year-over-year changes in transmission outage severity. Even the three-year CDM dataset has too small of a sample size for reliable correlation analysis or for the statistical analysis of differences in transmission outage severity.

Upon combining the three smallest ICC group (Vegetation; Environmental; and Vandalism, Terrorism, or Malicious Acts) into a new group (Combined Smaller ICC groups), the transmission risk and relative risk by ICC were calculated and ranked. Table A.8 provides a breakdown of relative risk of CDM events by ICC.

Table A.8: Evaluation of CDM Event ICC Contribution to Transmission Outage Severity (2012–2014)

Group of TADS events	Probability that an event from a group starts during a given hour	Expected Impact (expected transmission outage severity of an event)	Risk associated with a group per hour	Relative Risk by group
All TADS events	0.410	0.145	0.060	**100.0%**
All CDM events	0.061	0.226	0.014	**23.3%**
All CDM with ICC assigned	0.060	0.224	0.013	**22.5%**
CDM Lightning	0.0103	0.2394	0.002	**4.1%**
CDM Misoperation	0.0109	0.2202	0.002	**4.0%**
CDM Failed AC Substation Equipment	0.0086	0.2270	0.002	**3.3%**
CDM Unknown	0.0052	0.2270	0.001	**2.0%**
CDM Weather, excluding lightning	0.0047	0.2221	0.001	**1.7%**
CDM Human Error (w/o Type 61 OR Type 62)	0.0045	0.2273	0.001	**1.7%**
CDM Power System Condition	0.0045	0.2152	0.001	**1.6%**
CDM Failed AC Circuit Equipment	0.0038	0.2378	0.001	**1.5%**
CDM Other	0.0026	0.1854	0.000	**0.8%**
CDM Foreign Interference	0.0022	0.1823	0.000	**0.7%**
CDM Fire	0.0013	0.2440	0.000	**0.5%**
CDM Contamination	0.0009	0.2530	0.000	**0.4%**
CDM Combined Smaller ICC groups	**0.0006**	**0.1467**	**0.000**	**0.1%**

Analysis of the TADS CDM events indicated that events with ICCs of Misoperation and Failed AC Substation Equipment are the two largest contributors to transmission outage severity with the exception of weather-related events. However, there is no significant correlation between any ICC and the transmission outage severity, which might be due to insufficient sample size of ICC groups and the whole CDM dataset for three years.

Sustained Event ICC Study (2012 to 2014)

TADS provides information to classify automatic outages as momentary or sustained.[97] A momentary outage is defined as an automatic outage with an outage duration less than one minute. If the circuit recloses and trips again within less than a minute of the initial outage, it is only considered one outage. The circuit would need to remain in service for longer than one minute between the breaker operations to be considered as two outages. A sustained outage[98] is defined as an automatic outage with an outage duration of a minute or greater. The definition of sustained outage has been extended to a TADS event with duration of a minute or greater. It is important to monitor and understand sustained outages and sustained events due to their potential risk to system reliability. Since outage duration is not included in the definition of transmission outage severity (Equation A.1), NERC staff studied the transmission outage severity of sustained events by ICC.

Table A.9 lists sustained events by ICC in the 2012 to 2014 database and their percentages with respect to all TADS events with a given ICC. Unlike all TADS events and CDM events, events with an Unknown ICC represented the largest number of sustained events. Sustained events initiated by Weather excluding Lightning ICC comprise the second largest group, followed by Lightning and Misoperation. Overall, 5908 sustained events were reported, representing 54.8 percent of all TADS events from 2012 to 2014. Out of these, 5878 are assigned to one of the 16 ICCs.

Almost all ICC groups of sustained events have sufficient data available to be used in a statistical analysis. Only two ICCs (Vandalism, Terrorism, or Malicious Acts; and Environmental) do not have enough observations for reliable statistical inferences based on the 2012 to 2014 data. These are combined into a new group, named "Combined Smaller ICC Groups," that can be statistically compared to every other group and used for reliable correlation analysis and for the statistical analysis of differences in transmission outage severity.

[97] http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx.

[98] The TADS definition of Sustained Outage is different from the NERC *Glossary of Terms Used in Reliability Standards* definition of Sustained Outage that is presently only used in FAC-003-1. The glossary defines a Sustained Outage as follows: "The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure." The definition is inadequate for TADS reporting for two reasons. First, it has no time limit that would distinguish a sustained outage from a momentary outage. Second, for a circuit with no automatic reclosing, the outage would not be "counted" if the TO has a successful manual reclosing under the glossary definition.

Table A.9: Sustained Events and Hourly Event Probability by ICC (2012–2014)				
Initiating Cause Code	**ALL TADS events**	**Sustained events**	**Sustained as % of ALL**	**Sustained Event Initiation Probability/Hour**
Unknown	2201	864	39.3%	0.0328
Weather, excluding lightning	1320	836	63.3%	0.0318
Lightning	2374	702	29.6%	0.0267
Misoperation	916	697	76.1%	0.0265
Failed AC Circuit Equipment	733	572	78.0%	0.0217
Failed AC Substation Equipment	662	562	84.9%	0.0214
Human Error (w/o Type 61 OR Type 62)	552	475	86.1%	0.0181
Foreign Interference	577	298	51.6%	0.0113
Fire	280	209	74.6%	0.0079
Power System Condition	269	188	69.9%	0.0071
Other	245	181	73.9%	0.0069
Contamination	460	171	37.2%	0.0065
Vegetation	118	89	75.4%	0.0034
Combined Smaller ICC groups	41	34	82.9%	0.0013
Vandalism, Terrorism, or Malicious Acts	27	22	81.5%	0.0008
Environmental	14	12	85.7%	0.0005
All with ICC assigned	10748	5878	54.7%	0.2235
All TADS events	10787	5908	54.8%	0.2246

Figure A.6 shows the correlation between calculated transmission outage severity and each ICC in the same format as Figure A.3.

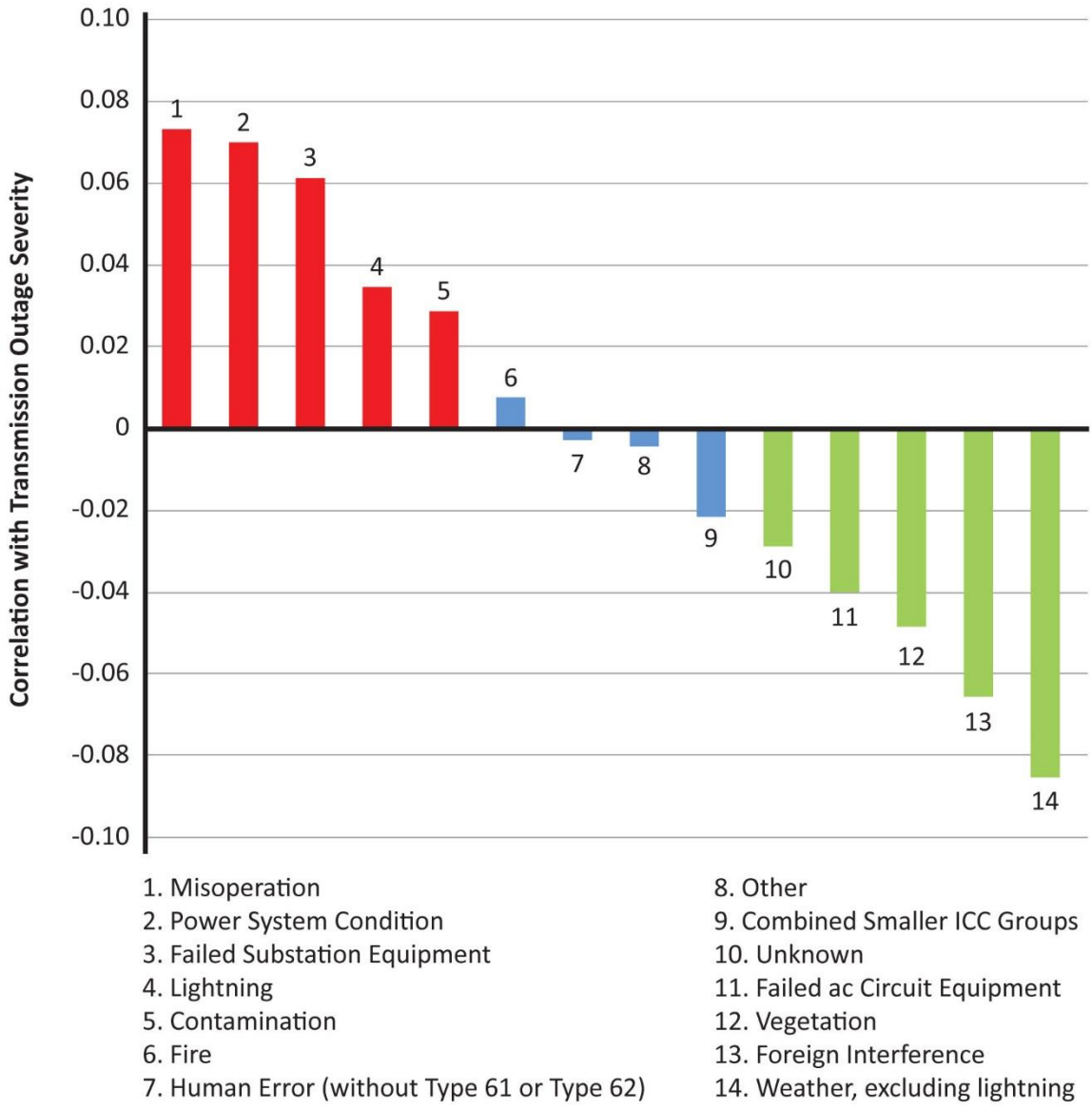


Figure A.6: Correlation between ICC and Transmission Outage Severity of Sustained Events (2012–2014)

Next, the distribution of transmission outage severity for the dataset was studied separately for sustained events with a given ICC. The sample statistics for transmission outage severity by ICC are listed in Table A.10 in the same format as Table A.4. Sustained events initiated by Power System Condition have the highest expected transmission outage severity, followed by events with ICCs Misoperation and Failed AC Substation Equipment. These groups not only have the statistically greater than expected outage severity than other sustained events, but also the greater variation, which means more frequent occurrences of events with these ICCs, which have very high transmission outage severity.

Table A.10: Distribution of Transmission Outage Severity of Sustained Events by ICC (2012–2014)

#	Initiating Cause Code (ICC)	Average TS	Is Expected TS statistically significantly different than for other sustained events?	ICC with statistically significantly smaller TS	Standard Deviation of TS
1	Power System Condition	0.196	Larger	2,3,4,5,6,7,8,9,10,11,12,13,14	0.18
2	Misoperation	0.175	Larger	5,6,7,8,9,10,11,12,13,14	0.15
3	Failed AC Substation Equipment	0.174	Larger	7,8,9,10,11,12,13,14	0.13
4	Contamination	0.171	Larger	9,10,11,12,13,14	0.10
5	Lightning	0.163	Larger	9,10,11,12,13,14	0.11
6	Fire	0.157	No	10,11,13,14	0.10
7	Human Error (w/o 61 OR Type 62)	0.155	No	10,11,13,14	0.11
	All Sustained Events	**0.154**	**N/A**	**N/A**	**0.11**
	Sustained with ICC	**0.153**	**N/A**	**N/A**	**0.11**
8	Other	0.150	No	11,13,14	0.12
9	Unknown	0.146	Smaller	11,13,14	0.09
10	Failed AC Circuit Equipment	0.140	Smaller	13,14	0.09
11	Weather, excluding lightning	0.132	Smaller	None	0.08
12	Combined Smaller ICC groups	0.123	Smaller	None	0.05
13	Foreign Interference	0.122	Smaller	None	0.07
14	Vegetation	0.110	Smaller	None	0.05

Finally, the transmission risk and relative risk by ICC were calculated and ranked. Table A.11 provides a breakdown of relative risk of CDM events by ICC.

Table A.11: Evaluation of Sustained Event ICC Contribution to Transmission Outage Severity (2012–2014)

Group of Sustained events	Probability that an event from a group starts during a given hour	Expected Impact (expected transmission outage severity of an event)	Risk associated with a group per hour	Relative Risk by group
All TADS events	0.410	0.145	0.0596	**100.0%**
All Sustained events	0.225	0.154	0.0346	**58.1%**
Sustained with ICC assigned	0.223	0.153	0.0342	**57.5%**
Unknown	0.033	0.146	0.0048	**8.0%**
Misoperation	0.026	0.175	0.0046	**7.8%**
Lightning	0.027	0.163	0.0044	**7.3%**
Weather, excluding lightning	0.032	0.132	0.0042	**7.0%**
Failed AC Substation Equipment	0.021	0.174	0.0037	**6.2%**
Failed AC Circuit Equipment	0.022	0.140	0.0030	**5.1%**
Human Error (w/o Type 61 OR Type 62)	0.018	0.155	0.0028	**4.7%**
Power System Condition	0.007	0.196	0.0014	**2.4%**
Foreign Interference	0.011	0.122	0.0014	**2.3%**
Fire	0.008	0.157	0.0013	**2.1%**
Contamination	0.007	0.171	0.0011	**1.9%**
Other	0.007	0.150	0.0010	**1.7%**
Vegetation	0.003	0.110	0.0004	**0.6%**
Combined Smaller ICC groups	0.001	0.123	0.0002	**0.3%**

Analysis of the TADS sustained events indicated that the ICC Unknown has the greatest relative risk for sustained events from 2012 to 2014. Sustained events with ICCs of Misoperation and Failed AC Substation Equipment are the two largest contributors to transmission outage severity with the exception of weather-related events. Also, they have a significant positive correlation with transmission outage severity. The ICC with the highest expected severity, Power System Condition, ranks low in Table A.11; its relative risk is small due to rare occurrences of sustained events with this ICC.

Regional Entity Transmission Analysis

For the first time, NERC performed a study of the transmission outage severity of TADS events by Region. This analysis is based on the 2012–2014 TADS data and utilizes the general methodology described in the previous sections. Here, a summary of this analysis is introduced and similarities and differences in transmission risk profiles by Region are examined. Figure A.7 shows the breakdown of NERC-wide inventory and transmission outage severity risk by Region.

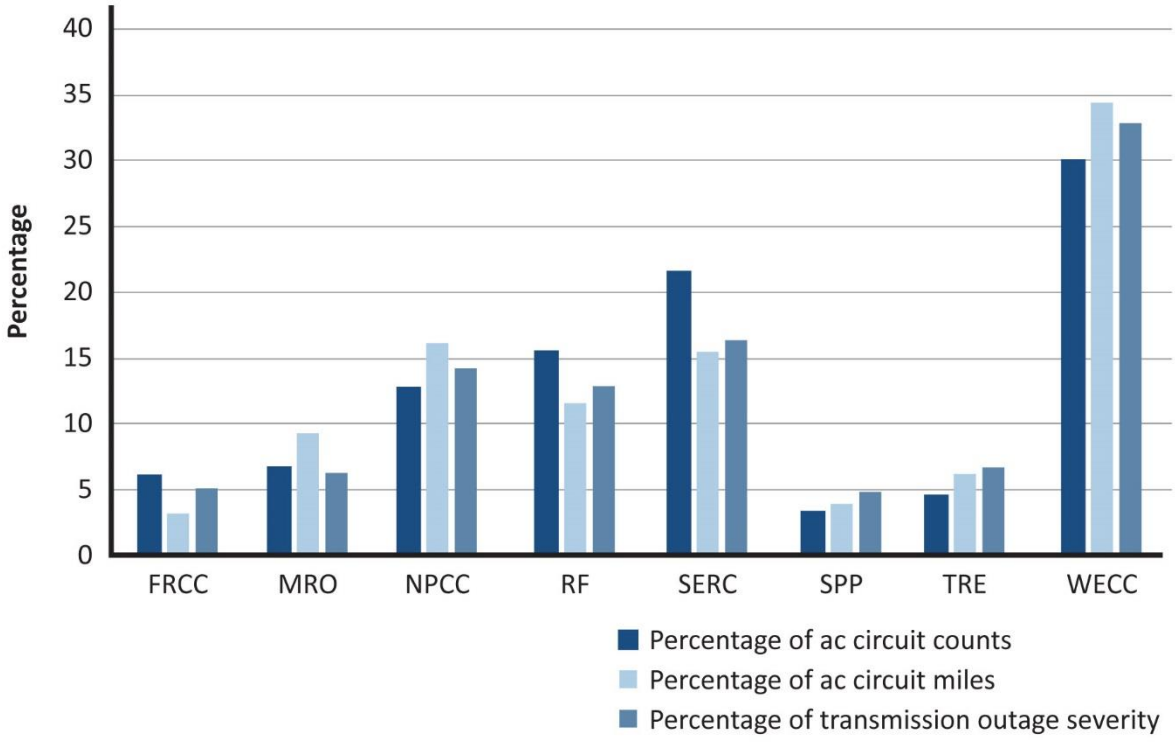


Figure A.7: NERC Inventory and Transmission Outage Severity Breakdown by Region (2012–2014)

Next, the transmission outage severity by initiating cause was studied for each Region. As for the entire NERC study described in the previous sections, three ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; and Environmental) were grouped into a new group, named "Combined Smaller ICCs." A comparative analysis of Regional Entity relative risks by ICC is summarized in Figure A.8. Figure A.8 represents the breakdown by relative risk by Region and for NERC. Initiating causes are listed from left to right by decreasing relative risk for NERC data.

For the top NERC ICCs, the relative risks vary dramatically among Regions. Relative risk for Lightning ranges from 10 percent in FRCC to 32 percent for SPP. Events with ICC Unknown contribute between 9 percent for RFC and 30 percent in WECC. Weather excluding Lightning, as an outage cause code, initiates events comprising 9 percent transmission outage severity in NPCC and 24 percent in MRO.

Misoperation has the highest relative risk in NPCC (18 percent) and the lowest in FRCC (6 percent) with other Regions' numbers close to the NERC average of 10 percent. For MRO, AC Substation Equipment failures resulted in only 4 percent of the total transmission outage severity, while they contributed 13 percent in RFC.

FRCC has a very distinctive profile with unique risk breakdown. First, the top-three ICCs for North America (two weather-related and Unknown) comprise only 34 percent of the transmission outage severity in FRCC, versus 54 percent for NERC. Second, FRCC's top-risk ICC is Foreign Interference, which ranks very low for NERC and other

Regions. Note that NERC's top non-weather-related contributors, Misoperation and Failed AC Substation Equipment, together comprise only 13 percent of FRCC's transmission risk compared with 14 percent for Failed AC Circuit Equipment.

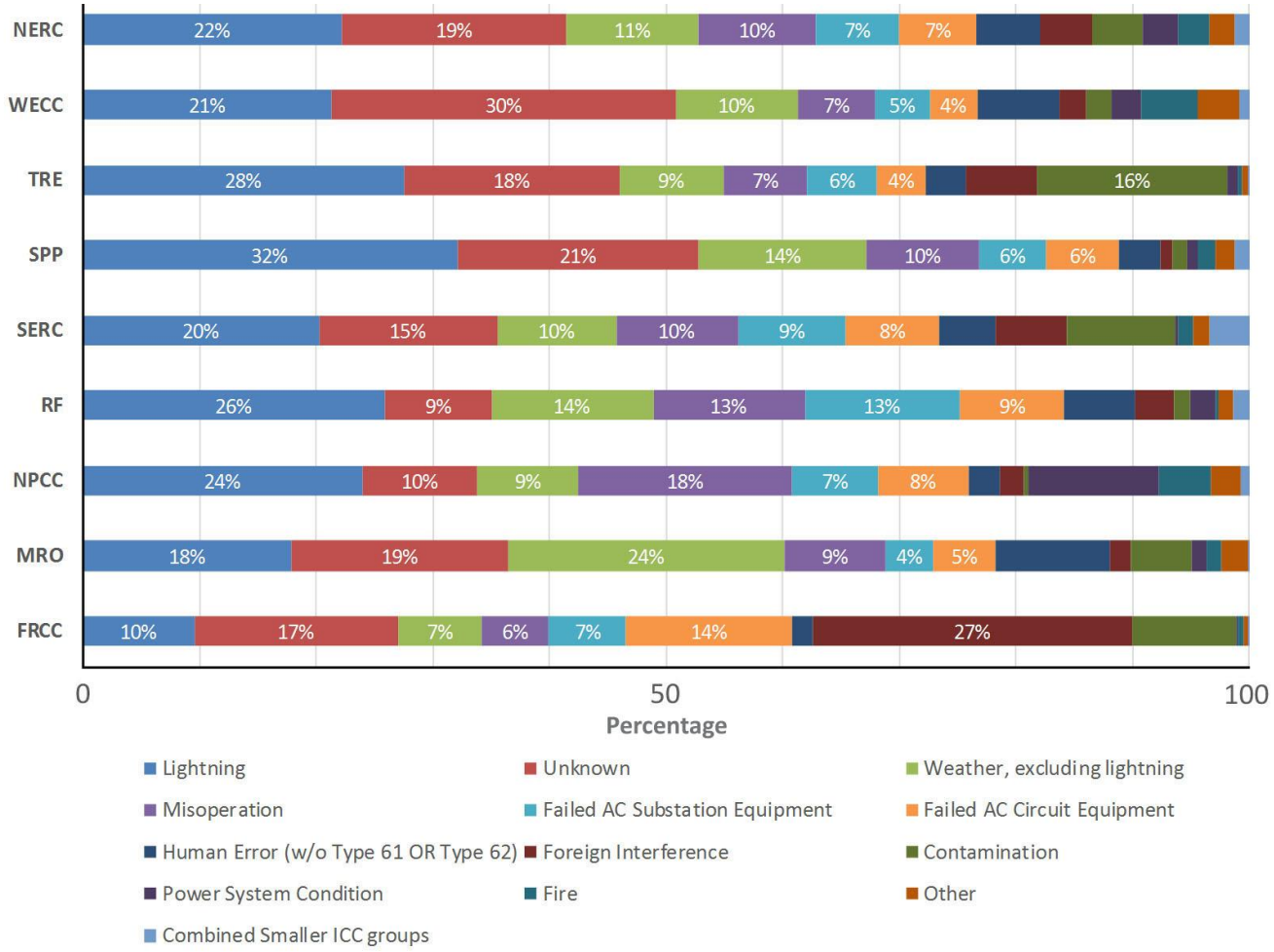


Figure A.8: Relative Transmission Risk by ICC and Region (2012–2014)

Summary of Analysis

The summary of the analysis of the risk profile of the 2012 to 2014 TADS events combined study is provided in Chapter 3. The Misoperation ICC (which represents TADS ICCs Failed Protection System Equipment and Human Error associated with Misoperations) and the Failed AC Substation Equipment ICC both show a statistically significant positive correlation with transmission outage severity and a higher relative transmission risk. Power System Condition ICC, while showing a positive correlation of transmission outage severity, has a lower relative transmission risk, based on the probability of this TADS outage event initiating in any hour and its expected transmission outage severity. On the other end of the risk spectrum, Lightning ICC shows a high relative transmission risk but has no significant correlation with transmission outage severity.

Figure A.9 represents an analysis of the risk profile of the 2012 to 2014 ICC study of sustained events. The x-axis is the magnitude of the correlation of a given ICC with transmission outage severity. The y-axis represents the expected transmission outage severity of an event when it occurs. The color of the marker indicates if there is a correlation of transmission outage severity with the given ICC (either positive – Red, negative – Green, or no significant correlation – Blue). The size of the marker indicates the probability of an event initiating in any hour

with a given ICC. Note that Failed AC Substation Equipment and Lightning both show a statistically significant positive correlation with transmission outage severity and show a higher relative transmission risk. On the other end of the risk spectrum, Weather excluding Lightning shows a high relative transmission risk but has no significant correlation with transmission outage severity.

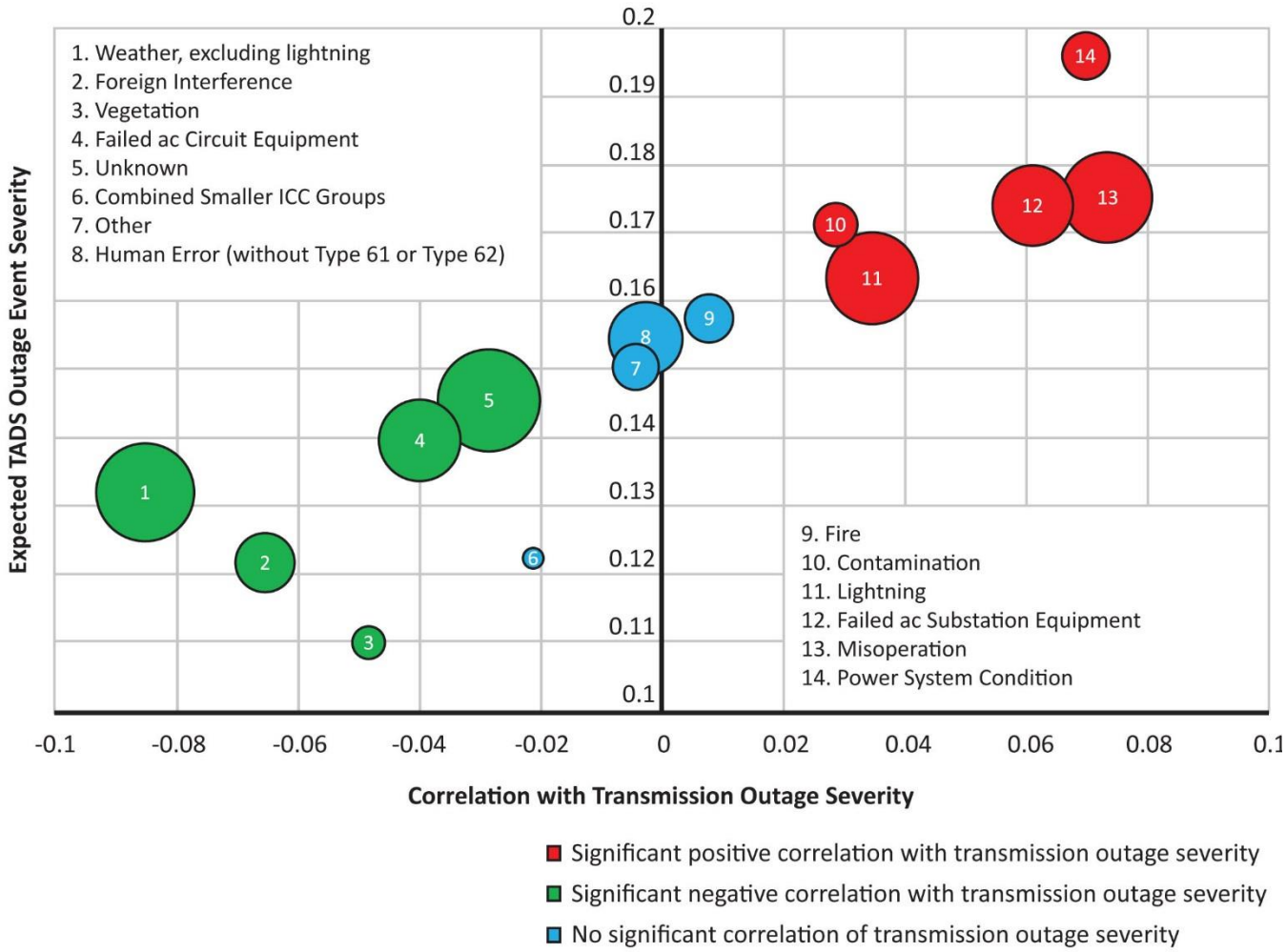


Figure A.9: Risk Profile of the 2012–2014 Sustained Events by ICC

The statistical analysis of the 2012 to 2014 TADS data on the transmission outage severity and initiating causes of TADS outage events yields the following observations:

- Excluding Weather-related and Unknown ICCs, Misoperations and Failed AC Substation Equipment ICCs remain the two largest contributors to transmission outage severity risk for all TADS events and all sustained TADS events.
- TADS outage events initiated by either of these ICCs have statistically significant greater expected outage severity than all other TADS outage events.
- Among other ICCs, only Power System Condition has a statistically significant positive correlation with transmission outage severity, but events initiated by this reported cause are less frequent and together contribute only 2.9 percent to the total transmission outage severity of the 2012–2014 TADS events.
- Statistical tests show that the average transmission outage severity of the events initiated by both Misoperations and Failed AC Substation Equipment ICC significantly decreased in 2014 versus 2012.

- Sustained TADS events with Unknown ICCs is an area that warrants further investigation by the TADSWG to determine:
    - The sustained outage events that have an Unknown ICC, and
    - The relative risk of events with both an initiating and sustained cause code of Unknown.
- The ICCs of TADS outage events are very different by Region.

Appendix B – Analysis of Generation Data

Introduction

The development of the Generating Availability Data System (GADS) began in 1982. GADS collects and stores unit operating information on a quarterly basis. By pooling individual unit information, overall generating unit availability performance is calculated. The information supports equipment reliability, availability analyses, and risk-informed decision making to industry. Finally, reports and information resulting from the data collected through GADS are used for benchmarking and analyzing electric power plants. Table B.1 shows some key characteristics of the population in the GADS database. The processing of 2014 GADS data is planned for completion by June 30, 2015.

Table B.1: Key Characteristics of the GADS Database

Metric/Year	2011	2012	2013
Number of Units > 20 MW	5,398	6,991	5,812
Average Age of the Fleet in Years	37.99	34.97	35.69
Average Age Fossil Units in Years	43.84	42.53	42.94

The age of the generating fleet is a particularly revealing statistic for GADS, since an aging fleet will potentially see increasing outages. Figure B.1 uses the GADS dataset to plot fleet capacity against age by fuel type. Figure B.1 shows two characteristics of the fleet reported to GADS: (1) there is an age bubble around 39–47 years, and that population is driven by coal and some gas units; (2) there is a significant age bubble around 11–13 years comprised almost exclusively of gas units. The data set shows a clear shift toward gas-fired unit additions, and the overall age of the fleet across North America is almost 10 years younger than the age of the coal-fired baseload plants that have been the backbone of power supply for many years. This trend is projected to continue given current forecasts around price and availability of natural gas as a power generation fuel, as well as regulatory impetus.

Generator Fleet Reliability

The GADS data set contains information that can be used to compute a number of reliability measures, including EFORd, a metric that measures the probability that a unit will not meet its demand periods for generating requirements because of forced outages or deratings.

Figure B.2 presents the monthly megawatt-weighted EFORd across the NERC footprint for the five-year period 2009–2013. The average outage rate over that period is 4.8 percent. EFORd has been fairly stable with only a few significant excursions, as indicated by the highlighted bars in the chart. In this case, significant excursions are at least one standard deviation higher.

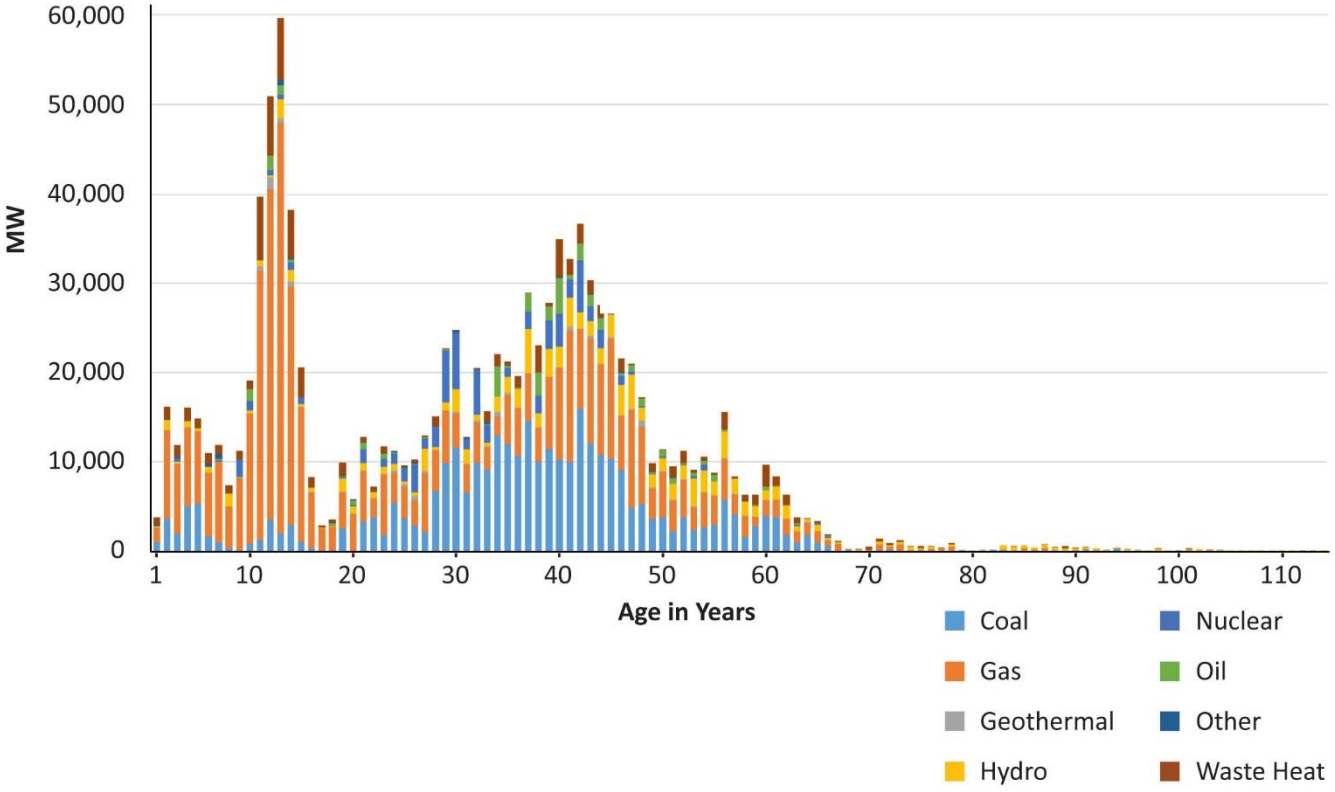


Figure B.2: Fleet Capacity against Age by Fuel Type

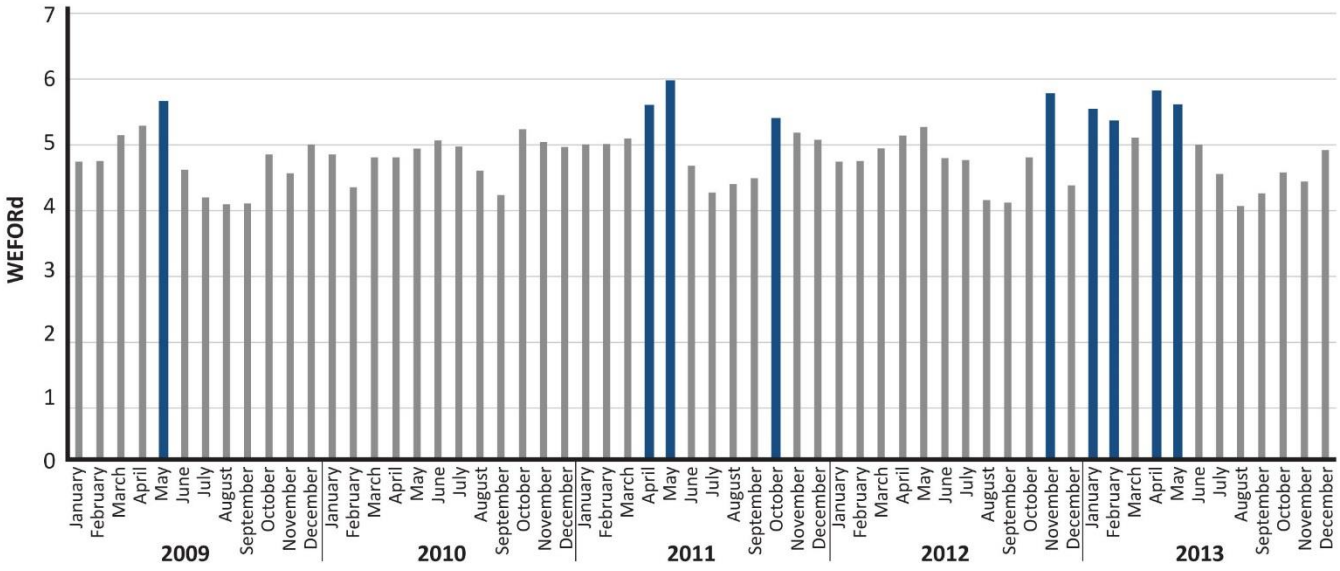


Figure B.2: Monthly Capacity Weighted EFORd 2009–2013

Top-10 Outage Causes

To better understand the cause of generator outages, the top-10 causes of unit outages for the summer and winter seasons were reviewed, as well as the annual causes, for the period 2012–2014. This analysis is focused on the top causes other than weather-related causes, measured in terms of lost megawatt hours, so it captures both the amount of capacity affected and the duration of the outages.

The level of outages reported into the GADS database is presented in Figure B.3, which shows the total duration of unit outages for the period 2012 to 2014 by season.

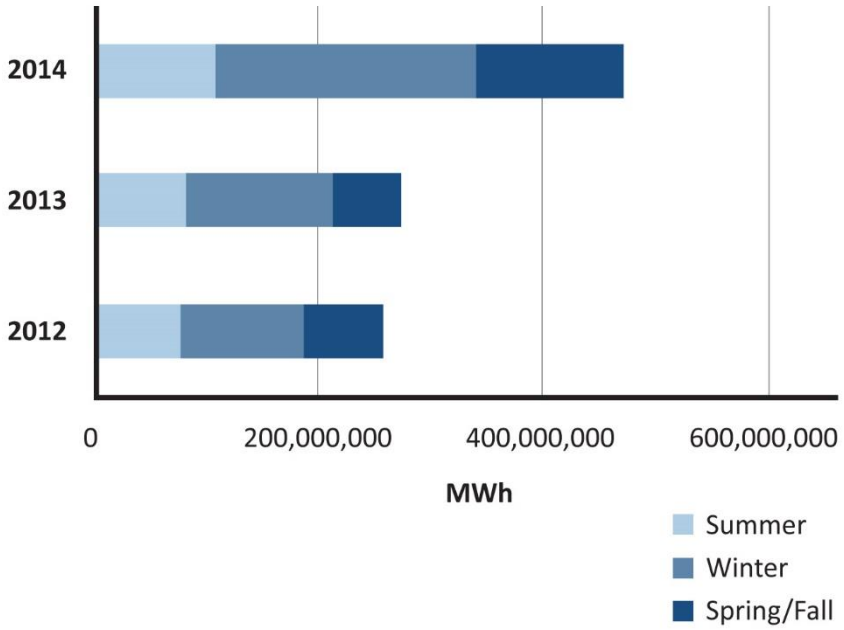


Figure B.3: Total Duration of Unit Outages 2012–2014

NERC	Annual MWh	Summer	Winter	Spring/Fall
2012	292,002,962	77,110,158	110,215,976	104,676,828
2013	306,500,709	82,522,997	131,075,905	92,901,806
2014	515,967,236	108,357,518	232,204,485	175,405,232

Based on the three years of available data, the following observations can be made:

- Summer lost megawatt hours have remained relatively consistent over the three-year period.
- Generally, lost megawatt hours in the winter season are greater than other periods of the year.
- The winter season lost megawatt hours show a significant excursion in 2014, driven in large part by outages related to the polar vortex.
- The sharp increase in the annual value of lost megawatt hours reported in 2014 is driven by the winter seasonal outages.

To provide insight into the drivers for the reported lost megawatt hours, the top-10 causes (exclusive of weather-related causes) have been examined to determine how much of a contribution is made by the top causes. Figure B.4 shows the contribution of the top-10 causes on a NERC-wide basis over the period 2012–2014. This is a three-year snapshot of the contributions by summer, winter, and annual impact.

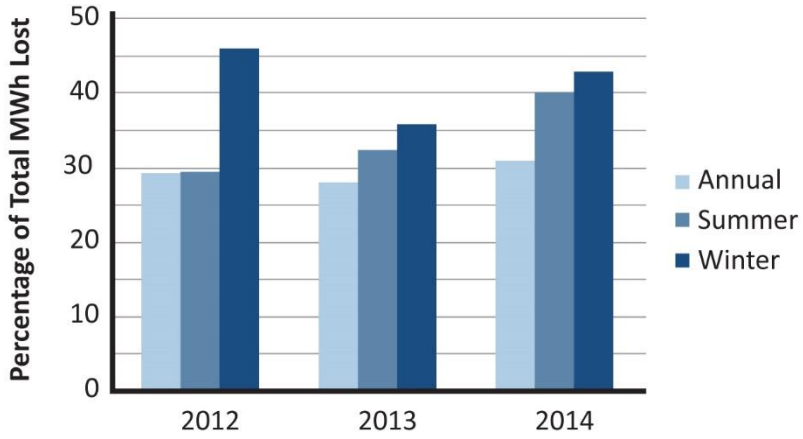


Figure B.4: Contribution of Top-10 Cause Codes 2012–2014

NERC	Annual	Summer	Winter
2012	0.2930	0.2957	0.4609
2013	0.2803	0.3237	0.3576
2014	0.3085	0.4027	0.4308

Based on this data set, the contribution from the top-10 causes to the total non-weather megawatt hours lost is about 30 percent; the remaining 70 percent of causes contribute less than 1 percent of the lost megawatt hours. It appears that in the 2014 data, the summer top-10 contributions have increased almost 10 percent compared to the results from 2012–2013. This change will be more fully analyzed as additional data becomes available. The contribution of the top-10 in the winter season is greater than the summer contribution and appears more variable.

The top-10 causes changes across the years and seasons, and the contribution from each of the top-10 causes to the total megawatt hours lost varies as well. Figure B.5 shows the contribution from each of the top-10 causes that accumulate to the total top-10 annual impacts shown in Figure B.4.

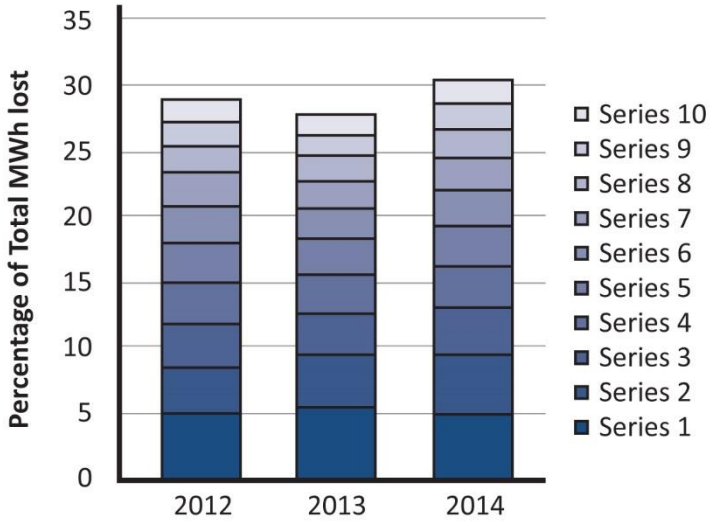


Figure B.5: Contribution of the Individual Top-10 Cause Codes to Top-10 Impacts

Table B.2 lists the top-10 causes on an annual basis; the list is ordered from the most impactful cause to the least within the top 10.

Table B.2: Top-10 Cause Codes on an Annual Basis

Series	2012	2013	2014
1	Waterwall (Furnace wall) A	Waterwall (Furnace wall) A	Boiler; miscellaneous
2	Transmission system problems	Main transformer	Waterwall (Furnace wall) A
3	Rotor; General	Rotor; General	Emergency generator trip devices
4	Steam generator tube leaks	Second superheater B	Lack of fuel (int supply of fuel)
5	Main transformer	Operator error	Main transformer
6	Steam generator tube inspections	Stator windings; bushings; terminals	Electrostatic precipitator fouling
7	Containment structure	Stator; General	Other low-pressure turbine problems
8	Second superheater B	Rotor windings	AC Conductors and buses
9	Generator output breaker	First reheater A	Stator windings; bushings; terminals
10	Other boiler I&C	First superheater B	Major turbine overhaul (720 hours or longer

Within the top-10 causes, there is some consistency and also some variability, although of limited sample size to draw long-term trends or conclusions. In addition to this type of annual view of the top-10 causes, seasonal variation in outage causes is summarized in Table B.3; this listing is organized around the top-5 annual outage causes and shows the seasonal ranking of these annual top 5 for the summer and winter periods.

Table B.3: Seasonal Ranking of the Top-5 Summer and Top-5 Winter Cause Codes

Year	Cause Code	Annual	Summer	Winter
2012	Waterwall (Furnace wall) A	1	1	6
	Transmission System Problems	2	3	3
	Rotor; General	3	8	
	Steam generator tube leaks	4		1
	Main transformer	5	5	7
2013	Waterwall (Furnace wall) A	1	1	
	Main transformer	2		1
	Rotor; General	3	2	
	Second superheater B	4	5	8
	Operator error	5		
2014	Boiler; miscellaneous	1		1
	Waterwall (Furnace wall) A	2	2	4
	Emergency generator trip devices	3		
	Lack of fuel (int supply of fuel)	4		2
	Main transformer	5	4	

Recommendations

- NERC, through the GADSWG, should continue to investigate seasonal performance trends for all types of reported generation. As the generation fleet continues to shift toward gas-fired units, and the overall age of the fleet reduces, new emerging trends must be examined to identify common outage concerns across fuel types.
- NERC, through the GADSWG, should trend forced outage rates to determine if there are immediate concerns with newly installed generation.
- NERC, through the GADSWG, should examine outage cause codes for specific equipment types (e.g., generator, boiler, turbine, etc.)
- NERC should investigate a shorter deadline for reporting annual data to facilitate better analysis in future state of reliability reports.

Appendix C – Analysis of Demand Response Data

Overview

Since 2012, the DADS Working Group (DADSWG) has continued to work to improve the detailed demand response data. Actions taken in the last year include revising the DADS glossary of definitions, streamlining event type reporting, implementing changes to the webDADS portal, and updating the historically reported event type to align with revised terms. While these efforts have begun to address the issues identified, more work is necessary, and the work will continue throughout 2015 and into 2016. The data represented here reflects the improved process and is an accurate portrayal of information.

Demand Response – Registered Programs

Demand Response Registered Program data provides important information about the individual programs that include product type, service type, relationships to other entities and programs, and monthly registered capacities.

The webDADS portal collects information about demand response programs based on product type and product service type. Current product types in webDADS include Energy, Capacity, and Reserves. Table C.1 shows the product service types related to reliability within each product type. When a reporting entity registers a demand response program in webDADS, it identifies the product type and product service type.

Table C.1: DADS Product Type Categories

Product Type	Product Service Type
Energy	Emergency
Capacity	Direct Control Load Management Interruptible Load Load as a Capacity Resource
Reserves	Spinning Non-Spinning

Due to the efforts undertaken in 2014, comparisons between registered program capacities in 2013 and 2014 by Regional Entities and service product types are available.

Registered Capacity by Region

Figure C.1 compares the registered capacity megawatts for all Product Service Types by Region for the month of August in 2013 and 2014. The August 2013 value was 44,285 MW, and the August 2014 value was 44,583 MW, an increase of less than 1 percent.

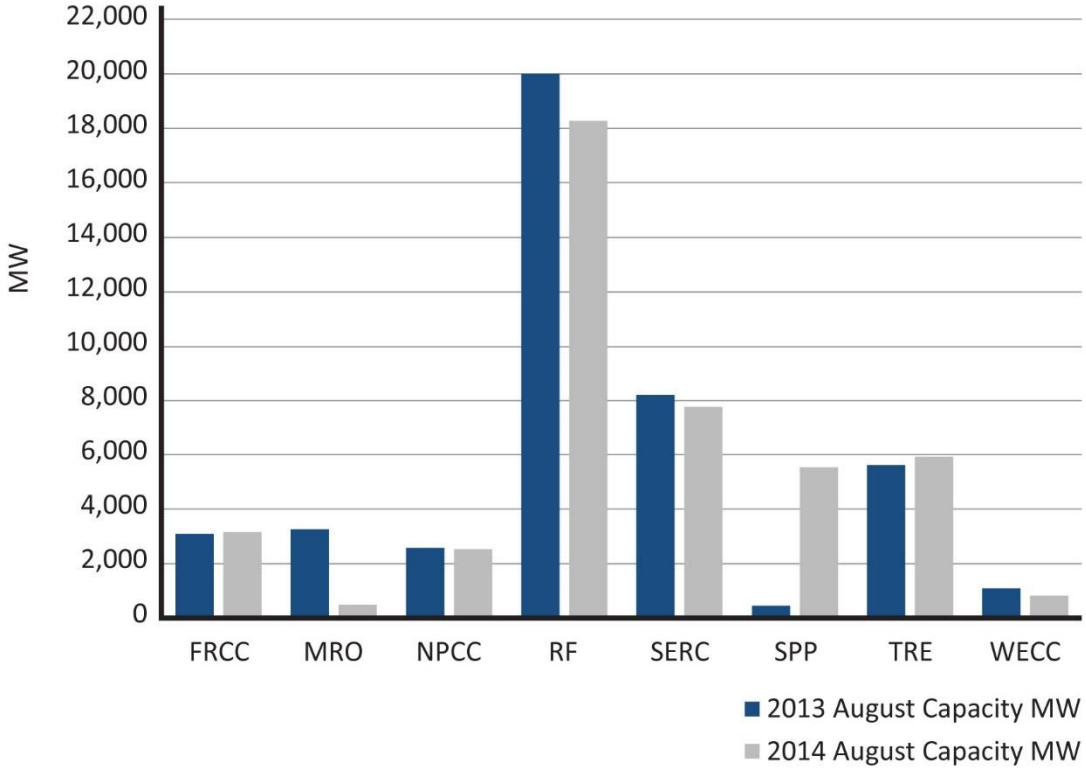


Figure C.3: Registered Capacity MW for all Product Service Types by Region – Aug. 2013 and 2014

Registered Capacity by Service Type

Figure C.2 shows a comparison of registered capacity megawatts by the product service type. In August, Load as a Capacity Resource appears to be the most common use of demand response resources for reliability (66 percent in 2013 and 58 percent in 2014), followed by Direct Control Load Management.

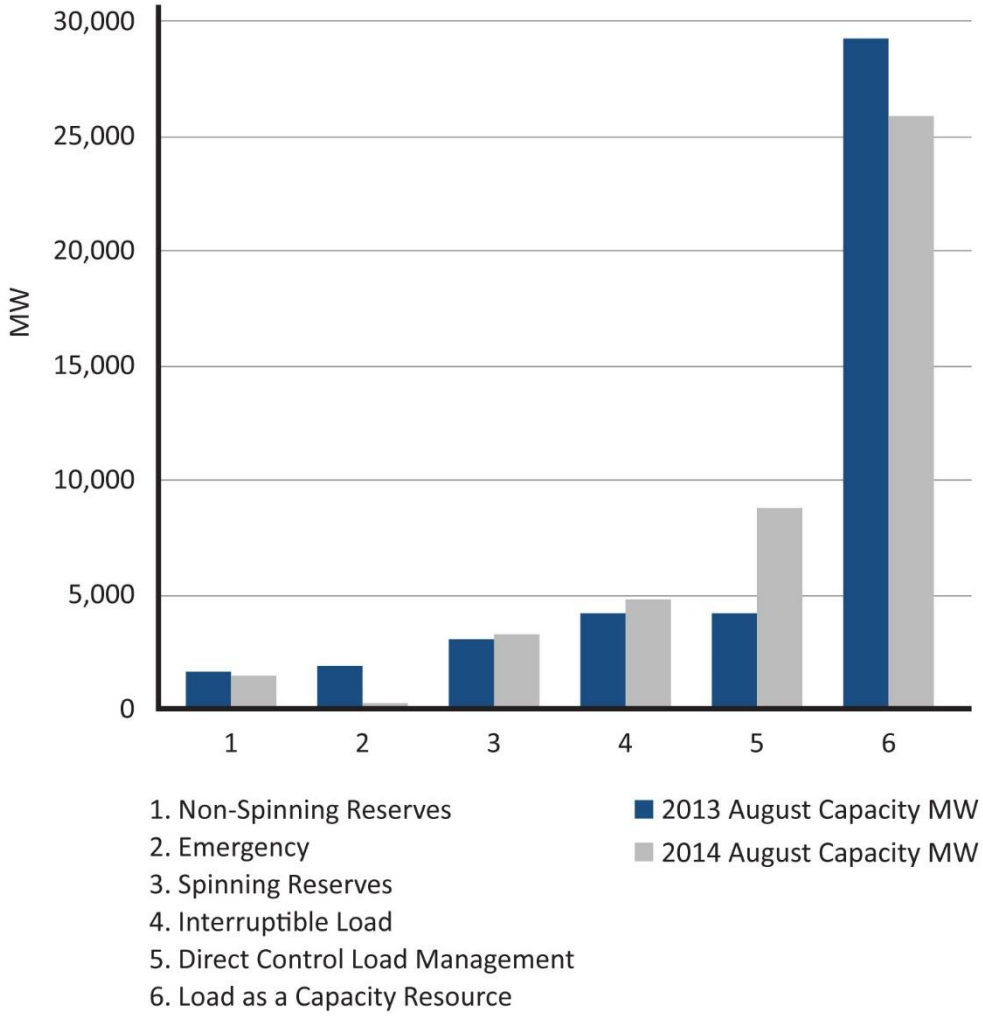


Figure C.4: Registered Capacity MW for all Regions by Service Type – Aug. 2013 and 2014

Demand Response – Reliability Events

When a demand response program is registered in webDADS, the entity selects a reporting type. The reporting type includes Reliability Events, Ancillary Services, or Market Participation. Figure C.3 represents all 2011–2014 reported Reliability Events as aggregated to the ISOs', RTOs', and BAs' webDADS hierarchy level.

Reliability Event reasons reported and summarized in webDADS are categorized as one of three types: Reliability Event, Frequency Control, and Forecast or Actual Reserve Shortage. Figure C.3 shows the number of days in each month, by Region, since demand response event reporting became mandatory in webDADS in April 2011. The black diamond shown on each column reflects the total number of days that a demand response event occurred in the month. When the column extends above the black diamond, it indicates that more than one Region used demand response on the same day. This view provides a perspective on how frequently demand response is used to resolve reliability issues.

For example, the summers of 2011 and 2012 were exceptionally hot, and the number of days demand response was dispatched in those summer months is much greater than in the other report years, even exceeding the number of days and regions where demand response was dispatched during the summer heat wave of 2013. The impact of the polar vortex is also evident in the number of days and regions that dispatched demand response in January 2014.

Figure C.3 illustrates that entities in the SERC and FRCC Regions use reliability demand response each month. The registered programs in these Regions are primarily Direct Control Load Management and Interruptible Load. The frequency of use of demand response in these programs may reflect a specific design characteristic of the program rather than an ongoing reliability issue.

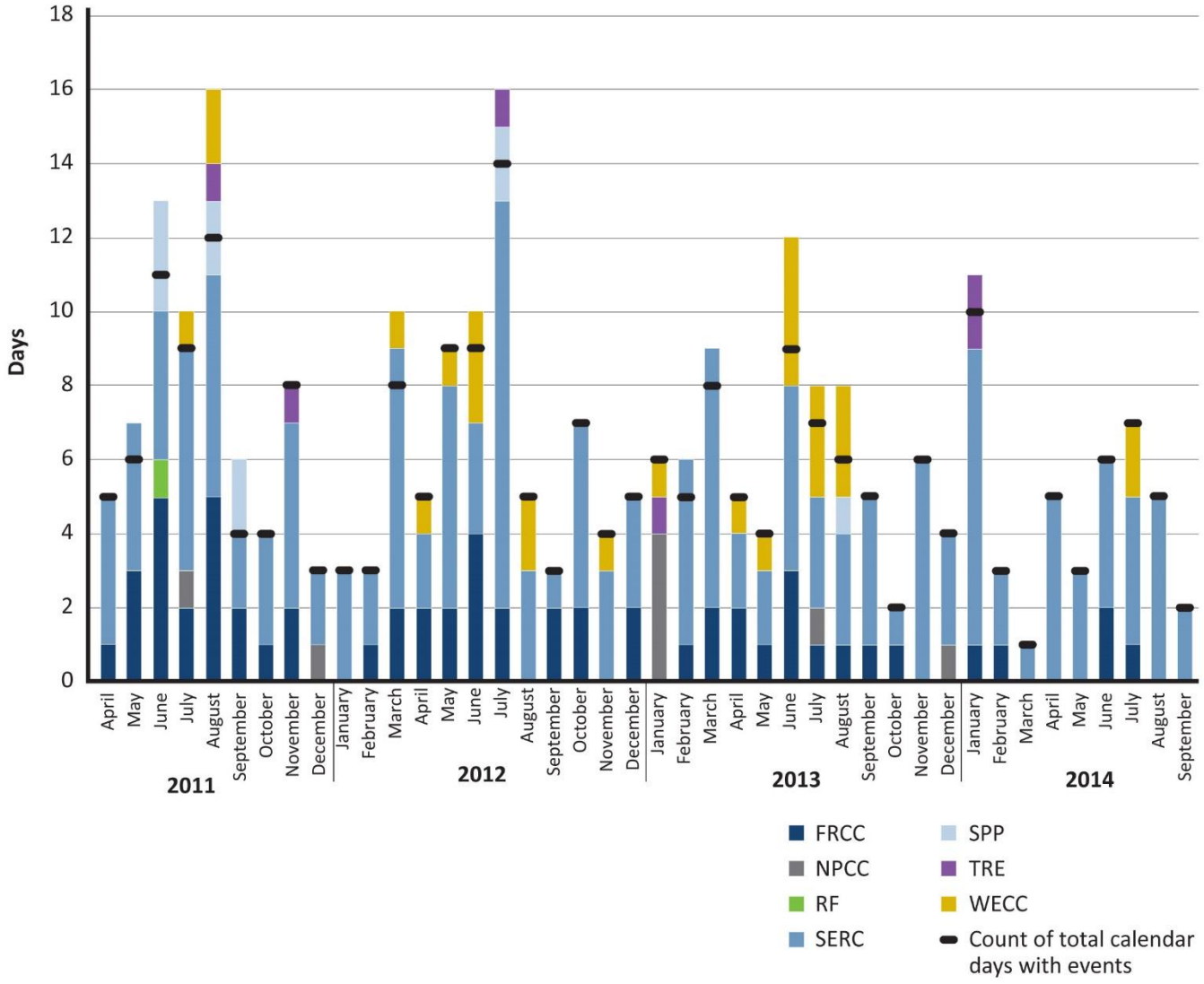


Figure C.5: Demand Response Events by Month and Region 2011–2014

Tables C.2–5 provide the data charted in Figure C.3. The tables provide the count of events by Region, the count of total calendar days with events, and the total dispatched megawatt value for all demand response events reported by month.

As a note of caution, the MW value shown for each month is an accumulation of all dispatched megawatts across all events in the month. The value is not an average or calculated value for the events and should not be proportioned to the count of events or days. Additionally, the number provided for the Calendar Days with Events is not the sum of event counts for the individual Regions.

Table C.2: Calendar Days in 2011 with Events by Region with Monthly Dispatched MW

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
FRCC				1	3	5	2	5	2	1	2	
NPCC							1					1
RF						1						
SERC				4	4	4	6	6	2	3	5	2
SPP						3		2	2			
TRE								1			1	
WECC							1	2				
Calendar Days with Events†				5	6	11	9	12	4	4	8	3
Dispatched MW				750	450	450	631	900	300	450	900	300

Table C.3: Calendar Days in 2012 with Events by Region with Monthly Dispatched MW												
	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
FRCC		1	2	2	2	4	2		2	2		2
NPCC												
RF												
SERC	3	2	7	2	6	3	11	3	1	5	3	3
SPP								2				
TRE								1			1	
WECC			1	1	1	3		2			1	
Calendar Days with Events†	3	3	8	5	9	9	14	5	3	7	4	5
Dispatched MW	300.0	161.8	1,200.0	296.9	583.6	311.7	1,026.0	167.0	-	712.5	570.0	427.5

Table C.4: Calendar Days in 2013 with Events by Region with Monthly Dispatched MW												
	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
FRCC		1	2	2	1	3	1	1	1	1		
NPCC	4						1					1
RF												
SERC		6	7	2	2	5	3	3	4	1	6	3
SPP								1				
TRE	1											
WECC	1			1	1	4	3	3				
Calendar Days with Events†	6	5	6	5	4	9	7	6	5	2	6	4
Dispatched MW	-	712.5	997.5	290.3	293.6	1,001.1	712.5	163.0	570.0	142.5	855.0	427.5

Table C.5: Calendar Days in 2014 with Events by Region with Monthly Dispatched MW

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
FRCC	1	1				2	1					
NPCC												
RF												
SERC	8	2	1	5	3	4	4	5	2			
SPP												
TRE	2											
WECC							2					
Calendar Days with Events†	10	3	1	5	3	6	7	5	2			
Dispatched MW	570.0	285.0	142.5	712.5	427.5	1,242.0	582.5	750.0	142.5			

Across North America, demand response is used an average of six times a month to respond to reliability events, dispatching an average of 500 MW each month. Additional analysis of the data collected using webDADS is needed; for example, it may be of interest to know if any of the days with demand response events experienced significant reliability problems.

The DADSWG will continue to work on data collection and reporting issues while monitoring and reporting on the availability and performance of demand response.

Appendix D – Statistical Analysis of Metrics

Interconnection Frequency Response: Time Trends

Eastern Interconnection

The time trend analysis uses the Eastern Interconnection frequency response (FR) datasets for 2012 to 2014. In this section, relationships between FR and the explanatory variable T (time = year, month, day, hour, minute, second) are studied. Figure D.1 shows the Eastern Interconnection FR scatter plot with a linear regression trend line, the 95 percent confidence interval for the data, and the 95 percent confidence interval for the slope of the time trend line.

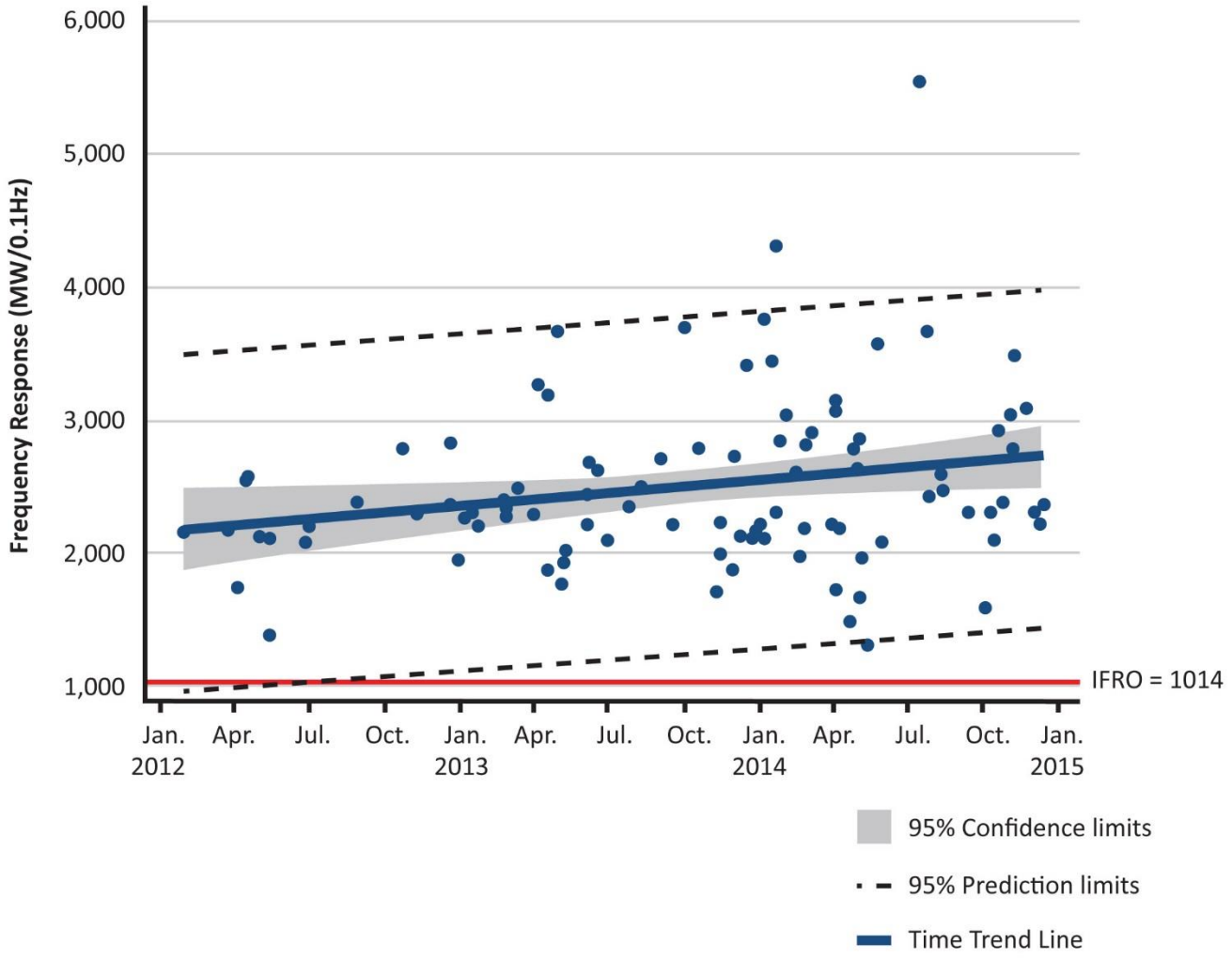


Figure D.1: Eastern Interconnection +FR Scatter Plot and Time Trend Line 2012–2014

There is a positive correlation of 0.22 between T and FR; further, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) results in a rejection of the null hypothesis about zero correlation (p-value of both tests was below 0.029). This proves that it was very unlikely that the observed positive correlation occurred simply by chance. Moreover, a linear trend line for the scatter plot connecting T and FR shown in Figure D.1 has a statistically significant positive slope (0.00000595), the linear regression is statistically significant, and on average, the Eastern Interconnection FR increased from 2012 through 2014 at the average rate of 15.0 MW/.1 Hz.

Western Interconnection

The time trend analysis uses the Western Interconnection FR data sets from 2012 through 2014. The FR values represent the observed values of the analysis (response) variable FR. In this section, the relationship is investigated between FR and the explanatory variable T, when an FR event happened. Figure D.2 shows the Western Interconnection frequency response scatter plot with a linear regression trend line, the 95 percent confidence interval for the data, and the 95 percent confidence interval for the slope of the time trend line.

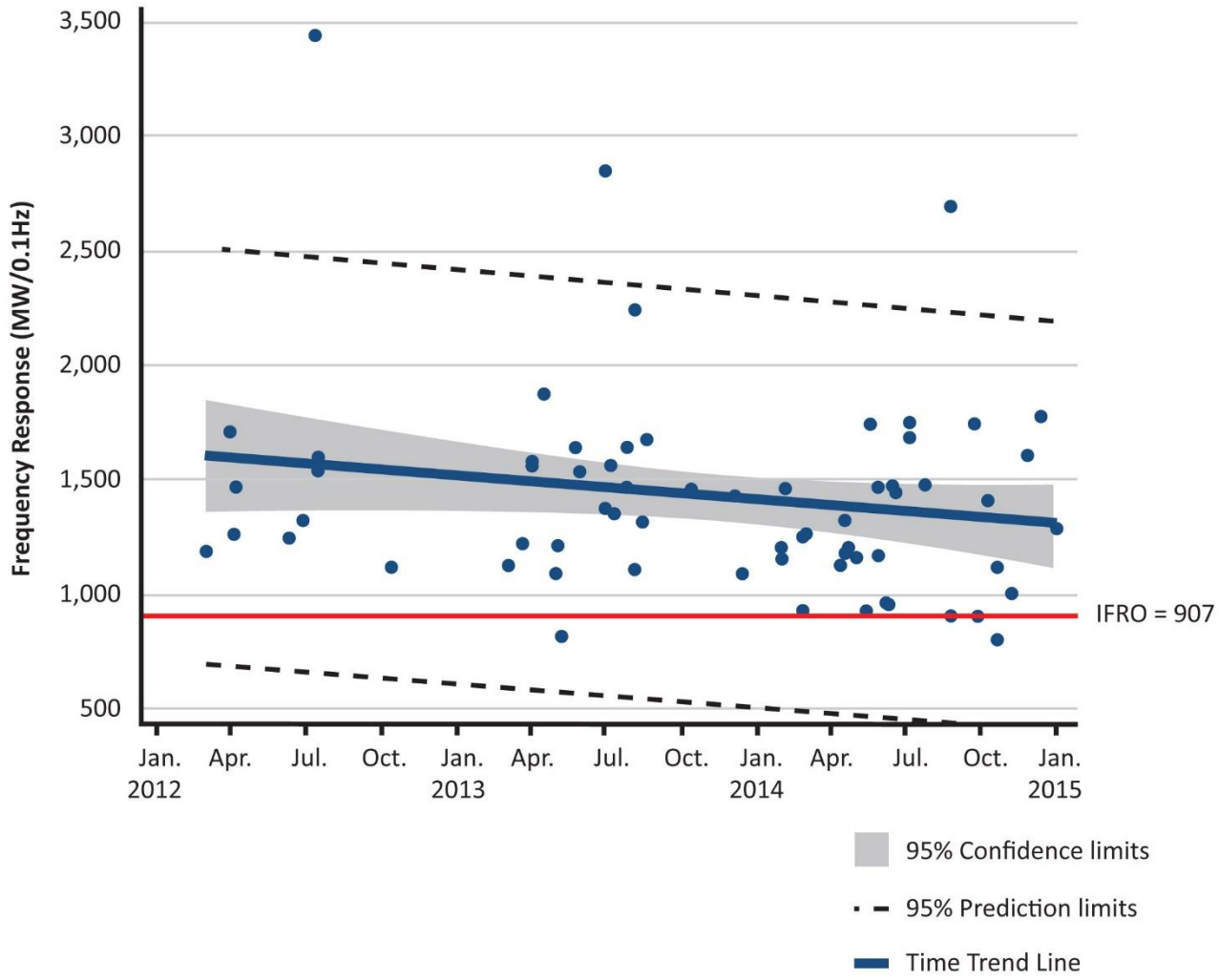


Figure D.2: Western Interconnection Frequency Response Scatter Plot and Time Trend Line 2012—2014

There is a negative correlation of -0.19 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p value of both tests is 0.13). This result leads to the conclusion that the negative correlation could have occurred simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR shown in Figure D.2 has a negative slope (-0.00000336), the linear regression is not statistically significant, and on average, the Western Interconnection FR has been stable from 2012 through 2014.

ERCOT Interconnection

The time trend analysis uses the ERCOT Interconnection FR datasets for 2012 to 2014. In this section, the relationship is investigated between FR and the explanatory variable T, when an FR event happened. Figure D.3 shows the ERCOT Interconnection FR scatter plot with a linear regression trend line, the 95 percent confidence interval for the data, and the 95 percent confidence interval for the slope of the time trend line.

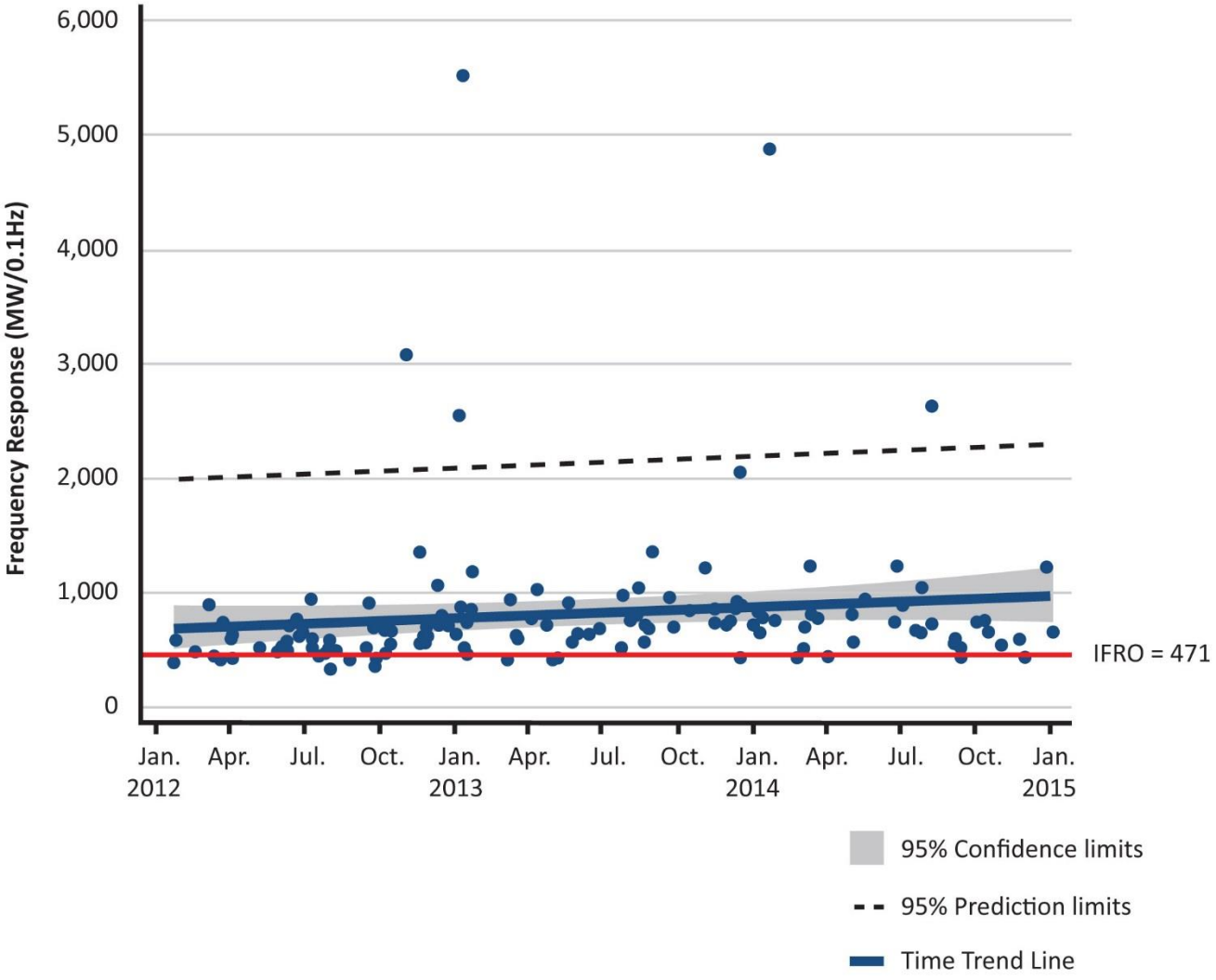


Figure D.3: ERCOT Interconnection Frequency Response Scatter Plot and Time Trend Line 2012—2014

There is a positive correlation of 0.12 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p-value of both tests is 0.17). This result leads to the conclusion that with high probability the positive correlation could occur simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR shown in Figure D.3 has a positive slope (0.00000304), the linear regression is not statistically significant, and on average, the ERCOT Interconnection FR has been stable from 2012 through 2014.

Québec Interconnection

The time trend analysis uses the Québec Interconnection FR datasets for 2012 to 2014. The FR values represent the observed values of the analysis (response) variable FR of the Québec Interconnection FR. In this section, the relationship is investigated between FR and the explanatory variable T, when an FR event happened. Figure D.4 shows the Québec Interconnection FR scatter plot with a linear regression trend line, the 95 percent confidence interval for the data, and the 95 percent confidence interval for the slope of the time trend line.

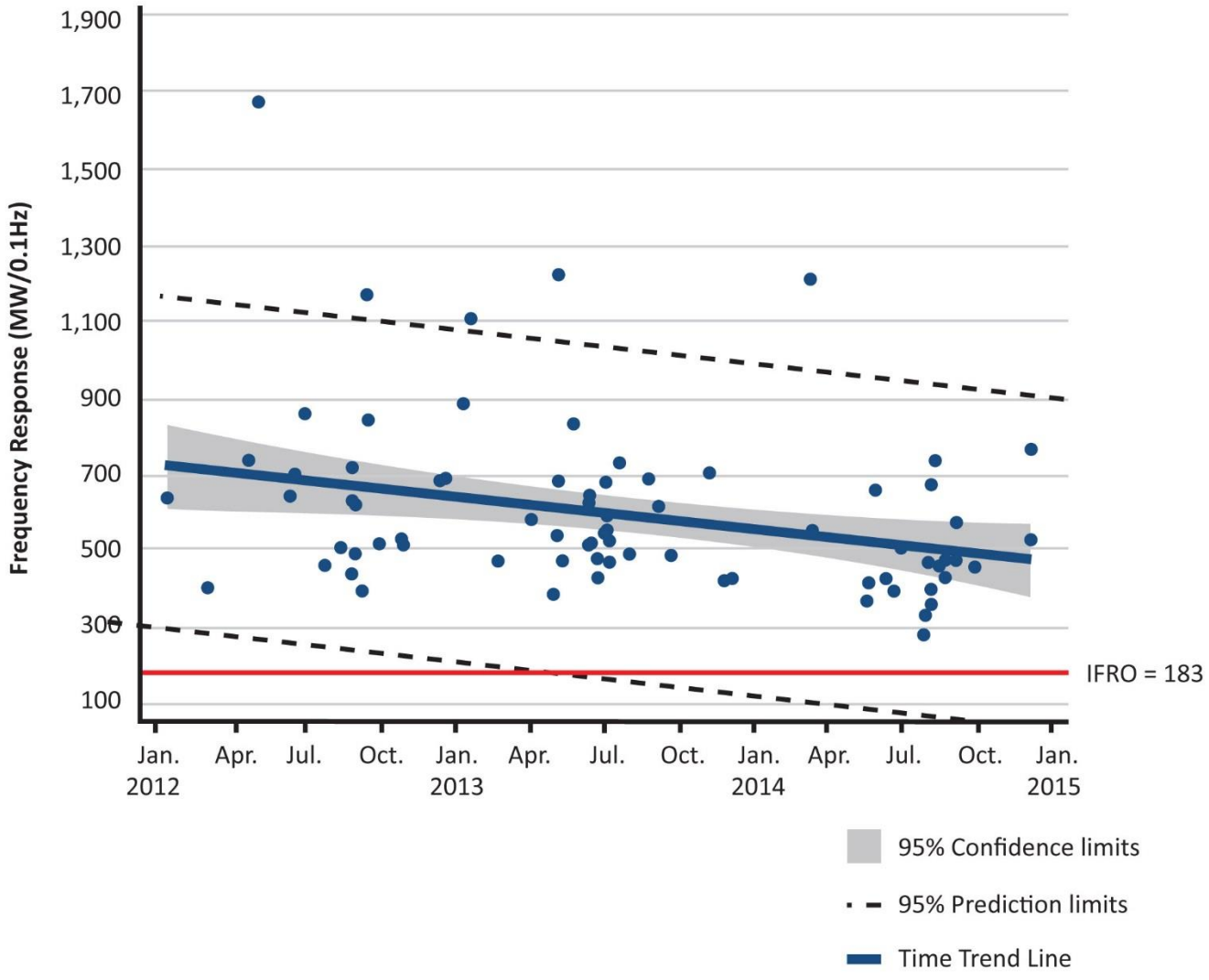


Figure D.4: Québec Interconnection Frequency Response Scatter Plot and Time Trend Line 2012—2014

There is a negative correlation of -0.31 between T and FR; further, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) results in a rejection of the null hypothesis about zero correlation (p-value of both tests is below 0.007). This proves that it was very unlikely that the observed negative correlation occurred simply by chance. Moreover, a linear trend line for the scatter plot connecting T and FR shown in Figure D.4 has a statistically significant negative slope (-0.00000269), the linear regression is statistically significant, and on average, the Québec Interconnection FR decreased from 2012 through 2014 at the average rate of 6.8 MW/.1 Hz.

Interconnection Frequency Response: Year-to-Year Changes

Eastern Interconnection

The time trend analysis uses the Eastern Interconnection FR datasets from 2012 through 2014. The sample statistics by year are listed in Table D.1. The last column lists the number of FR events that fell below the absolute IFRO.[99]

Next, Fisher's Least Significant Difference test was used to analyze all pair-wise changes in FR. These tests result in the conclusion that there was a statistically significant increase of FR in 2014 compared with 2012, and there were no other statistically significant changes in the expected FR by year for the Eastern Interconnection.

Table D.1: Sample Statistics for Eastern Interconnection

Year	Number of Values	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO of 1014 MW/0.1 Hz
2012-2014	**97**	**2488.28**	**642.43**	**2307.43**	**1300.26**	**5552.36**	**0**
2012	16	2229.13	368.22	2187.47	1374.02	2824.55	0
2013	36	2415.84	500.78	2282.03	1707.03	3696.28	0
2014	45	2638.38	776.53	2469.33	1300.26	5552.36	0

[99] http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf

Figure D.5 shows the box plot of the annual distribution of the Eastern Interconnection FR. Each box encloses the interquartile range with the lower edge at the first quartile and the upper edge at the third quartile. A line is drawn through the box at the second quartile, which is the median. A diamond shows the mean. A lower (upper) whisker connects the box with the smallest (the largest) data point within 1.5 interquartile ranges from the first (the third) quartile. Data farther from the box than the whiskers, plotted as individual points, are outliers. Table D.1 and Figure D.5 illustrate year-to year increases in the average FR as well as in its variation. Statistical tests find the only statistically significant difference in the year-over-year changes—the expected FR in 2012 is significantly less than in 2014.

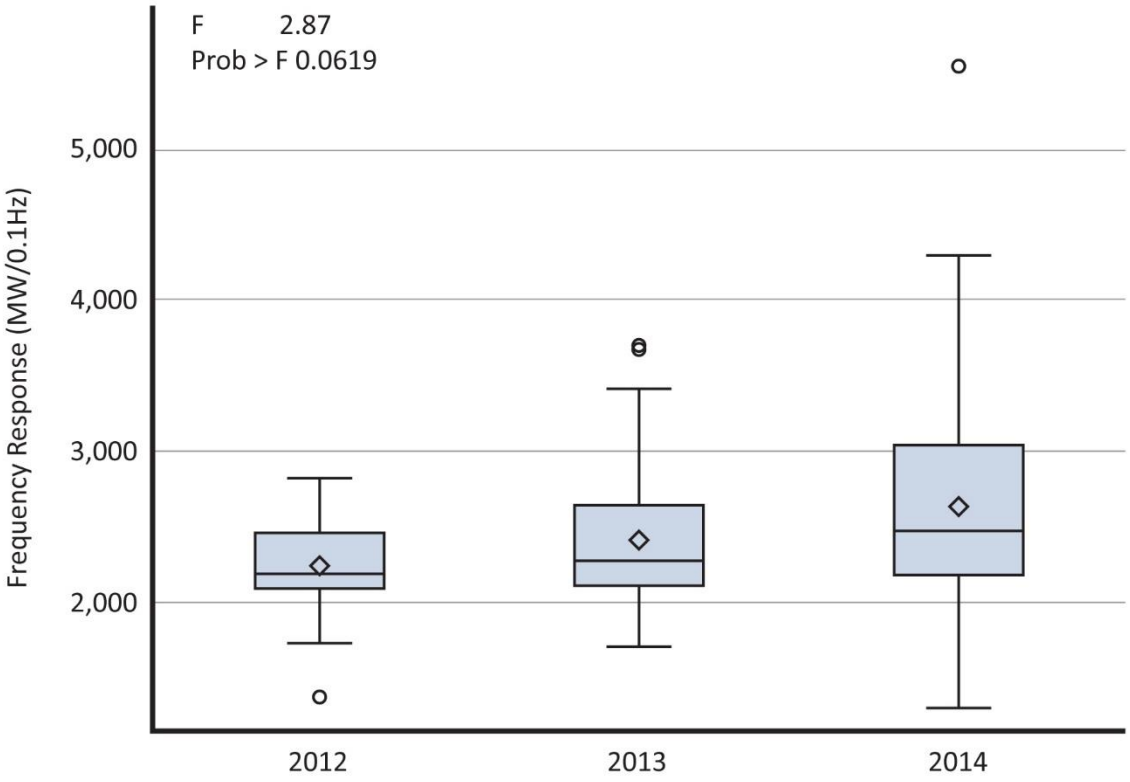


Figure D.5: Eastern Interconnection Frequency Response Distribution by Year 2012–2014

Western Interconnection

The time trend analysis uses the Western Interconnection FR datasets for 2012 through 2014. The sample statistics are listed by year in Table D.2. The last column lists the number of FR events that fell below the absolute IFRO.

Table D.2: Sample Statistics for Western Interconnection

Year	Number of Values	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO of 907 MW/0.1 Hz
2012-2014	**68**	**1419.06**	**444.92**	**1336.80**	**798.34**	**3439.70**	**4**
2012	10	1590.47	677.49	1396.43	1120.51	3439.70	0
2013	23	1489.99	421.93	1463.11	821.85	2850.99	1
2014	35	1323.47	363.24	1265.64	798.34	2695.58	3

Figure D.6 shows the box plot of the annual distribution of the Western Interconnection FR. There are no statistically significant differences in the expected FR by year. In particular, this is due to too small of a sample size for 2012.

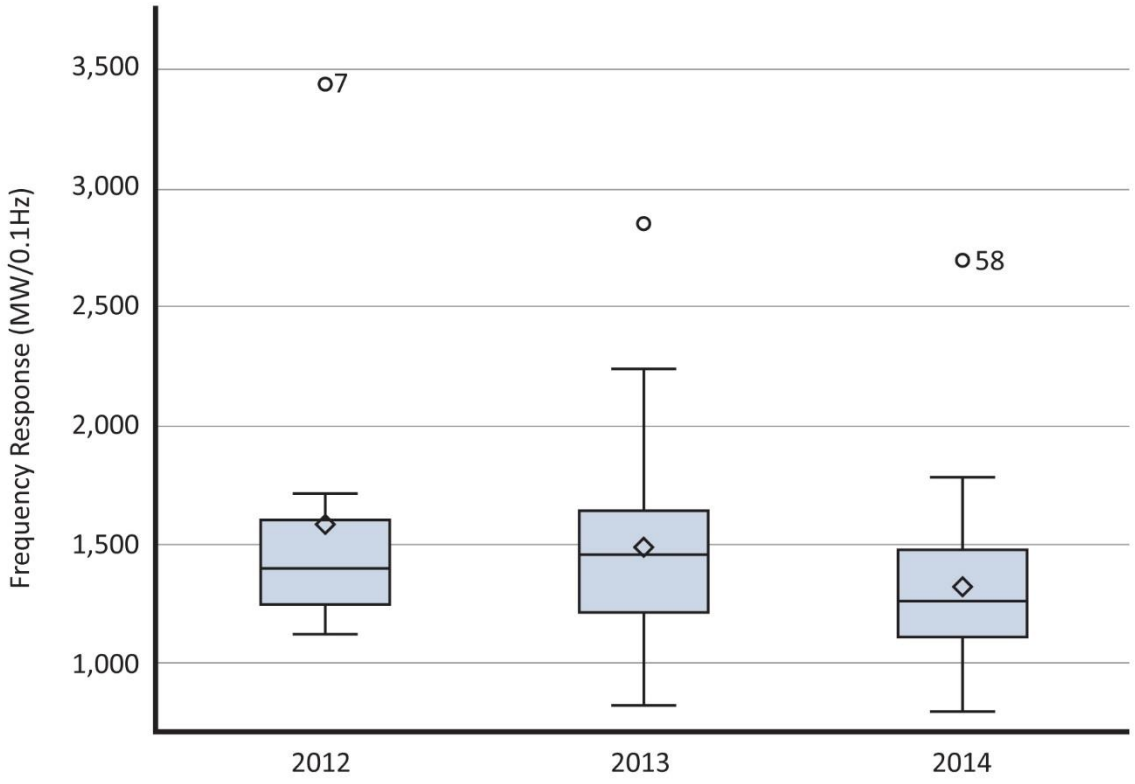


Figure D.6: Western Interconnection Frequency Response Distribution by Year 2012–2014

ERCOT Interconnection

The time trend analysis uses the ERCOT Interconnection FR datasets from 2012 through 2014. The sample statistics by year are listed in Table D.3. The last column lists the number of FR events that fell below the absolute IFRO.

Table D.3: Sample Statistics for ERCOT Interconnection

Year	Number of Values	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO of 471 MW/0.1 Hz
2012-2014	**138**	**809.70**	**661.67**	**663.83**	**336.77**	**5530.50**	**21**
2012	53	650.58	386.28	577.88	336.77	3082.64	12
2013	48	921.60	777.52	745.51	406.60	5530.50	5
2014	37	892.45	774.79	725.26	425.66	4879.72	4

Next, Fisher's Least Significant Difference test was used to analyze all pair-wise changes in FR. These tests result in the conclusion that there was a statistically significant increase of FR in 2013 compared with 2012, and there were no other statistically significant changes in the expected FR by year for the ERCOT Interconnection.

Figure D.7 shows the box plot of the annual distribution of the ERCOT FR. Statistical tests find the only statistically significant difference in the year-over-year changes—the expected frequency response in 2012 is significantly smaller than in 2013.

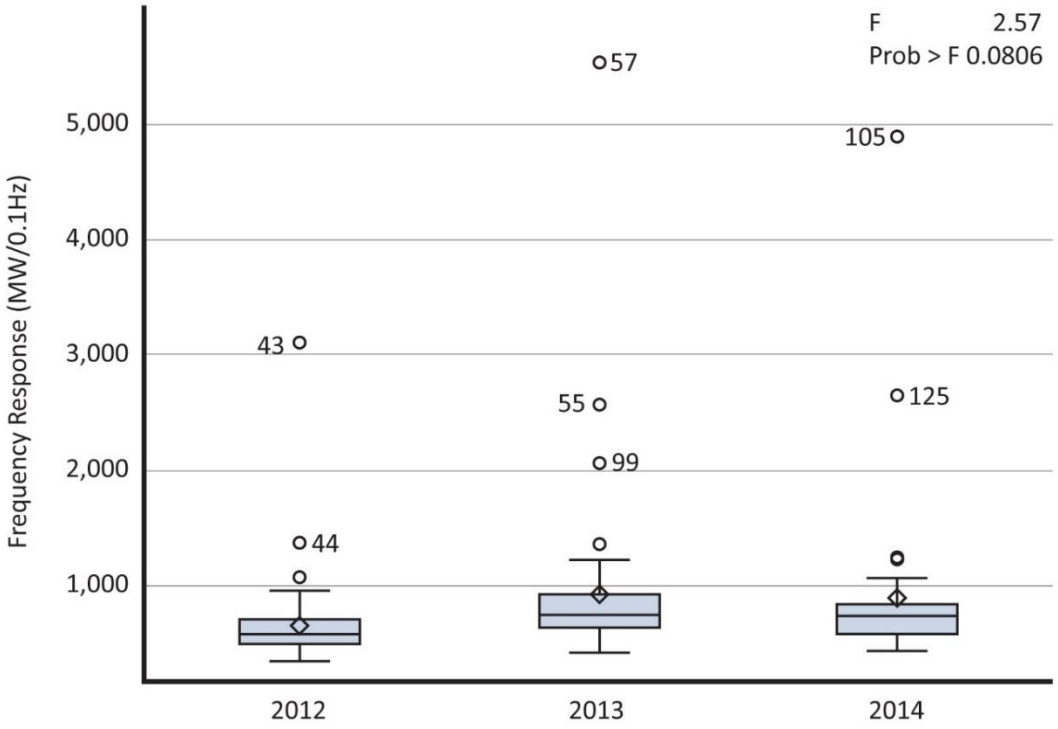


Figure D.7: ERCOT Frequency Response Distribution by Year 2012–2014

Several factors contributed to the FR performance in the ERCOT Interconnection during the years in which the FR did not meet the recommended IFRO (2011 and 2012).

- ERCOT has a small hydro fleet that suffered significantly due to the extreme drought of 2011. There was some relief in 2012, but not in the geographical area of these hydro facilities. Additionally, the owners of the facilities have changed the facilities' operation. Prior to the ERCOT nodal market implementation in December 2010, many of these facilities were operated as frequency responsive reserves. They were on-line in synchronous condenser mode and ramped to full output in about 20 seconds anytime frequency dropped to 59.900 Hz or below, providing 50 to 240 MW of primary FR (during the first 20 seconds of a disturbance). Since early 2011, this service has been discontinued.
- There was a drop in natural gas prices and a change in dispatch. The price change caused many of the large coal generators to shut down, and FR from these generators had been excellent. The combined-cycle facilities that replaced these units had difficulty getting FR to work consistently and correctly. Since the fall of 2012, FR from combined-cycle facilities has improved, due to TRE's efforts to work with these generators to improve their performance.
- Another contributing factor was the continued increase in wind generation in ERCOT that typically operates at maximum output. Without margin in the up direction, the Interconnection only benefits by curtailing wind generators during high-frequency excursions from these generators. When low-frequency excursions occur, the wind generators cannot provide additional output to increase Interconnection frequency.

Québec Interconnection

The time trend analysis uses the Québec Interconnection FR datasets for the years 2012 through 2014. The sample statistics by year are listed in Table D.4. The last column lists the number of FR events that fell below the absolute IFRO.

Table D.4: Sample Statistics for Quebec Interconnection

Year	Number of Values	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO of 183 MW/0.1 Hz
2012-2014	**74**	**591.8**	**220.6**	**526.9**	**288.3**	**1673.6**	**0**
2012	21	656.2	268.0	635.0	397.2	1673.6	0
2013	29	606.5	192.2	545.9	389.1	1227.8	0
2014	24	517.7	192.8	465.1	288.3	1212.4	0

Next, Fisher's Least Significant Difference test was applied to analyze all pair-wise changes in FR. Statistical tests find the only statistically significant difference in the year-over-year changes—the expected FR in 2012 is significantly greater than in 2014.

Figure D.8 shows the box plot of the annual distribution of the Québec Interconnection FR. Table D.4 and Figure D.8 illustrate year-to-year decreases in the average FR.

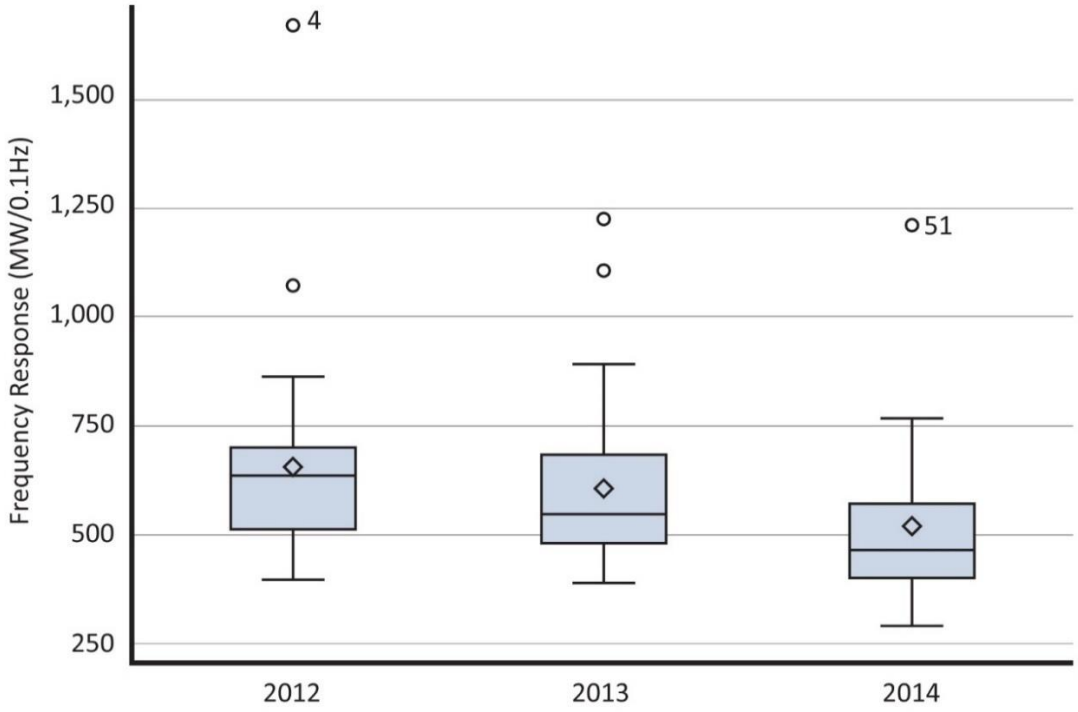


Figure D.8: Québec Interconnection Frequency Response Distribution by Year 2012–2014

Explanatory Variables for Frequency Response and Multiple Regression

Explanatory Variables

In the *2012 State of Reliability* report, Key Finding #2 proposed further work to see if specific indicators could be tied to severity of frequency deviation events. For each interconnection, the following set of six variables is included as explanatory variables (regressors) in the multiple regression models that describe the interconnection FR. These variables are not pair-wise uncorrelated, and some pairs are strongly correlated; however, all are included as candidates to avoid the loss of an important contributor to the FR variability. Model selection methods help ensure the removal of highly correlated regressors and run multicollinearity diagnostics (variance inflation diagnostics) for a multiple regression model selected.

Summer (Indicator Function) – Defined as 1 for FR events that occur from June through August, and 0 otherwise.
Winter (Indicator Function) – Defined as 1 for FR events that occur from December through February, and 0 otherwise.
High Pre-Disturbance Frequency (Indicator Function) – Defined as 1 for FR events with pre-disturbance frequency (point A) > 60 Hz, and 0 otherwise.
On-peak Hours (Indicator Function) – Defined as 1 for FR events that occurred during on-peak hours, and 0 otherwise. On-peak hours are designated as follows: Monday to Saturday from 0700 to 2200 (Central Time) excluding six holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.
Time – A moment in time (year, month, day, hour, minute, second) when an FR event happened. Time is measured in seconds elapsed between midnight of January 1, 1960 (the time origin for the date format in SAS), and the time of a corresponding FR event. This is used to determine trends over the study period.
Interconnection Load Level – Measured in megawatts.

Data Sets – Since the Interconnection Load Level data are available for 2012 and 2013 only, the correlation study and multivariate analysis with the explanatory variables are performed for 2012 through 2013 FR data for each interconnection. The two-year data sets have insufficient sizes for a good explanatory and predictive model, which requires estimates of big number parameters. An adequate model for each interconnection can only come with an annual increase of the FR data sets.

Table D.5 lists the ranks of statistically significant variables of FR for each interconnection. Positive indicates a statistically significant positive correlation, negative indicates a statistically significant negative correlation, and a dash indicates no statistically significant linear relation. A high pre-disturbance frequency has a statistically significant impact to FR in three interconnections. Events with A > 60 Hz on average have smaller FR than the events with A ≤ 60 Hz. If the initial predisturbance frequency is higher than 60 Hz, it is more likely that governor actions will be delayed because of the time it takes for the frequency to drop to the upper dead-band setting.

Table D.5: Observation Summary

Explanatory Valuable	Western	Eastern	ERCOT	Québec
Summer	1 (positive)	-	-	-
Winter	-	-	1 (positive)	-
High Pre-disturbance	-	1 (negative)	3 (negative)	1 (negative)
On-Peak hours	3 (negative)	-	-	-
Time	-	-	2 (positive)	-
Load Level	2 (positive)	-	-	-

Eastern Interconnection: Correlation Analysis and Multivariate Model

Descriptive statistics for the six explanatory variables and the Eastern Interconnection FR are listed in Table D.6.

Table D.6: Descriptive Statistics

Variable	N	Mean	Standard Dev.	Minimum	Maximum
Time	52			1/1/2012	12/31/2014
Winter	52	0.29	0.46	0	1
Summer	52	0.21	0.41	0	1
A > 60	52	0.38	0.49	0	1
On-Peak Hours	52	0.54	0.50	0	1
Interconnection Load	52	344906	50831	238949	472683
Frequency Response	52	2358.4	468.6	1374.0	3696.3

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the Eastern Interconnection frequency response shown in Table D.7. The value of a coefficient of determination R^2 indicates the percentage in variability of frequency response that can be explained by variability of the corresponding explanatory variable.

Table D.7: Correlation and Regression Analysis

Explanatory Variable	Correlation with FR	Statistically Significant (Yes/No)	Coefficient of Determination of Single Regression (If SS)
A > 60	-0.35	Yes	12.1%
Time	0.20	No	N/A
On-Peak Hours	0.07	No	N/A
Interconnection Load	0.05	No	N/A
Summer	-0.03	No	N/A
Winter	0.02	No	N/A

Out of the six parameters, only the indicator of high pre-disturbance frequency has a statistically significant correlation with FR. High predisturbance frequency is negatively correlated with FR; thus, the events with A > 60 Hz have statistically significantly smaller expected FR than the events with A ≤ 60 Hz. The other five variables do not have a statistically significant[100] linear relationship with FR.

[100] At significance level 0.1

Both step-wise selection and backward elimination algorithms[101] result in a single regression model that connects the Eastern Interconnection FR with the indicator of high predisturbance frequency (the other five variables are not selected or were eliminated). The model's coefficients are listed in Table D.8.

Table D.8: Coefficients of Multiple Model

Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	2485.83	78.45	31.69	<.0001	0.00
A> 60	1	-331.33	126.49	-2.62	0.01	1.00

The adjusted coefficient of the determination of the model is 10.3 percent; the model is statistically significant ($p < 0.01$). The random error has a zero mean and the sample deviation σ of 443.8 MW/.1 Hz. Since the multiple model for the Eastern Interconnection FR is reduced to a single model, no multicollinearity diagnostics are needed. The parameter estimate, or the coefficient for the high predisturbance frequency, indicates that on average, the Eastern Interconnection events with the predisturbance frequency A > 60 Hz have FR of 331 MW/.1 Hz smaller than events with A ≤ 60 Hz.

Frequency responses in the Eastern Interconnection are higher due to the large number of disturbances in the data set in which frequency changes were greater than the generator dead bands. Also, in earlier studies, the gross output of the unit trip was reported, rather than the net generation[102] megawatt loss to the interconnection.

[101] For step-wise regression algorithm and Backward Elimination algorithm see D. C. Montgomery and G. C. Runger. Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 499-501.

[102] There could be a coincident loss of load also.

Western Interconnection: Correlation Analysis and Multivariate Model

Descriptive statistics for the six explanatory variables and the Western Interconnection FR are listed in Table D.9.

Table D.9: Descriptive Statistics

Variable	N	Mean	Standard Dev.	Minimum	Maximum
Time	33			1/1/2012	12/31/2014
Winter	33	0.09	0.29	0	1
Summer	33	0.48	0.51	0	1
A > 60	33	0.58	0.50	0	1
On-Peak Hours	33	0.45	0.51	0	1
Interconnection Load	33	91285.2	16015	38321	118936
Frequency Response	33	1520.4	503.7	821.9	3439.7

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the Western Interconnection FR shown in Table D.10. The value of a coefficient of determination R^2 indicates the percentage in variability of FR that can be explained by variability of the corresponding explanatory variable.

Table D.10: Correlation and Regression Analysis

Explanatory Variable	Correlation with FR	Statistically Significant (Yes/No)	Coefficient of Determination of Single Regression (If SS)
Summer	0.36	Yes	13.1%
Interconnection Load	0.36	Yes	0.127985063
On-Peak Hours	-0.31	Yes	0.097144422
Winter	-0.18	No	N/A
A > 60	-0.16	No	N/A
Time	-0.06	No	N/A

Out of the six parameters, the three on the top have a statistically significant correlation with FR. The indicators of summer and interconnection load have a positive correlation with FR (the summer events have a greater FR, and the higher interconnection load, the greater FR). The indicator of on-peak hours has a negative correlation with FR, which is: on-peak-hour events have, on average, a smaller response. The other three variables are not statistically significantly[103] correlated with FR.

[103] At significance level 0.1

Finally, both the step-wise selection algorithm and the backward elimination algorithm result in a single regression model that connects the Western Interconnection FR with one regressor, the indicator of summer (the other five variables are not selected or were eliminated).[104] The coefficients of the single model are listed in Table D.11.

Table D.11: Coefficients of Multiple Model

Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1.00	1356.53	112.43	12.07	<.0001	0.00
Summer	1.00	360.6045300	166.765580	2.16	0.04	1.00

The adjusted coefficient of determination of the model is 10.3 percent; the model is statistically significant ($p = 0.04$). The random error has a zero mean and the sample deviation σ of 477.0 MW/.1 Hz. Since the multiple model for the Western Interconnection FR is reduced to a single model, no multicollinearity diagnostics are needed. The parameter estimate, or the coefficient for summer, indicates that on average, the summer events have FR 361 MW/.1 Hz greater than other events.

Note that although Table D.10 lists three explanatory variables for the Western Interconnection FR, Interconnection Load and On-Peak hours are eliminated from the final model due to their significant correlation with summer.

[104] Regressors in the final model have p-values not exceeding 0.1.

ERCOT: Correlation Analysis and Multivariate Model

Descriptive statistics for the six explanatory variables and the ERCOT Interconnection FR are listed in Table D.12.

Table D.12: Descriptive Statistics

Variable	N	Mean	Standard Dev.	Minimum	Maximum
Time	101			1/1/2012	12/31/2014
Winter	101	0.23	0.42	0	1
Summer	101	0.29	0.45	0	1
A > 60	101	0.42	0.50	0	1
On-Peak Hours	101	0.61	0.49	0	1
Interconnection Load	101	40532.4	9096	23252	64273
Frequency Response	101	779.4	616.6	336.8	5530.5

The correlation and a single-regression analysis result in the hierarchy of the explanatory variables for the ERCOT Interconnection FR shown in Table D.13. The value of a coefficient of determination R^2 indicates the percentage in variability of FR that can be explained by variability of the corresponding explanatory variable.

Table D.13: Correlation and Regression Analysis

Explanatory Variable	Correlation with FR	Statistically Significant (Yes/No)	Coefficient of Determination of Single Regression (If SS)
Winter	0.26	Yes	6.9%
Time	0.17	Yes	3.0%
A > 60	-0.17	Yes	2.8%
Interconnection Load	-0.13	No	N/A
Summer	-0.12	No	N/A
On-Peak Hours	0.04	No	N/A

Out of the six parameters, Winter and Time are statistically significantly positively correlated with FR (on average, frequency response increases in winter and grows with time). The indicator of high pre-disturbance frequency is statistically significantly negatively correlated with FR (the events with A > 60 Hz have smaller FR than the events with A ≤ 60 Hz). The other three variables do not have a statistically significant[105] linear relationship with FR.

[105] At significance level 0.1

Finally, both the step-wise selection algorithm and the backward elimination algorithm result in a single-regression model that connects the ERCOT Interconnection FR with the indicator of Winter (the other five variables are not selected or were eliminated)[106] as regressors. The coefficients of the multiple model (reduced to a single model) are listed in Table D.14.

Table D.14: Coefficients of Multiple Model

Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	692	68	10	<.0001	0
Winter	1	384	142	3	0.0081	1

The adjusted coefficient of determination of the model is 5.9 percent; the model is statistically significant ($p = 0.008$). The random error has a zero mean and the sample deviation σ of 598.1 MW/.1 Hz. Since the multiple models for the ERCOT Interconnection FR are reduced to a single model, no multicollinearity diagnostics are needed. The parameter estimate, or the coefficient for the winter, indicates that on average, the ERCOT events in winter have FR of 384 MW/.1 Hz greater than other events.

[106] Regressors in the final model have p-values not exceeding 0.1.

Québec: Correlation Analysis and Multivariate Model

Descriptive statistics for the six explanatory variables and the Québec Interconnection FR are in Table D.15.

Table D.15: Descriptive Statistics

Variable	N	Mean	Standard Deviation	Minimum	Maximum
Time	50			1/1/2012	12/31/2014
Winter	50	0.14	0.35	0	1
Summer	50	0.50	0.51	0	1
A > 60	50	0.52	0.50	0	1
On-Peak Hours	50	0.92	0.27	0	1
Interconnection Load	50	23863	4980	15736	36142
Frequency Response	50	627.4	225.9	389.1	1673.6

The correlation and a single-regression analysis result in the hierarchy of the explanatory variables for the Québec Interconnection FR shown in Table D.16. The value of a coefficient of determination R^2 indicates the percentage in variability of FR that can be explained by variability of the corresponding explanatory variable.

Table D.16: Correlation and Regression Analysis

Explanatory Variable	Correlation with FR	Statistically Significant (Yes/No)	Coefficient of Determination of Single Regression (If SS)
A > 60	-0.28	Yes	7.6%
Time	-0.23	No	N/A
On-Peak Hours	-0.20	No	N/A
Summer	-0.19	No	N/A
Winter	0.14	No	N/A
Interconnection Load	0.01	No	N/A

Out of the six parameters, only one explanatory variable is statistically significantly[107] correlated with FR. The indicator of high predisturbance frequency is negatively correlated with FR (the events with A > 60 Hz have smaller FR than the events with A ≤ 60 Hz). The other five variables do not have a statistically significant linear relationship with FR.

[107] At significance level 0.1

Finally, both the step-wise selection algorithm and the backward elimination algorithm result in a multiple regression model that connects the Québec Interconnection FR with Time, Summer and high predisturbance frequency (the other three variables are not selected or were eliminated).[108] The coefficients of the multiple model are in Table D.17.

Table D.17: Coefficients of Multiple Model

Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	9316.77	3300.09	2.82	0.01	0.00
Time	1	0.0000	0.00	-2.60	0.01	1.11
Summer	1	-103	58.21	-1.78	0.08	1.03
A > 60	1	-190	61.35	-3.10	0.003	1.14

The model's adjusted coefficient of multiple determination is 19.2 percent (that is almost 20 percent of the Québec Interconnection FR variability and can be explained by the combined variability of these three parameters); the model is statistically significant ($p = 0.005$). The random error has a zero mean and the sample deviation σ of 203 MW/.1 Hz. Variance inflation factors for the regressors do not exceed 1.14, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model.

A parameter estimate for time indicates a rate of decrease of the FR per unit of time (a second). It translated to the monthly decrease rate of 6.8 MW/0.1Hz. Parameter estimate for summer means that for fixed values of other variables, the summer events on average have FR of 103 MW/0.1 Hz smaller than other events. The main reason summer events have a smaller FR is because winter is the peak usage season in the Québec Interconnection. More generator units are on-line; therefore, there is more inertia in the system, so it is more robust in responding to frequency changes in the winter. Parameter estimate for high predisturbance frequency means that for fixed values of other variables, events with the predisturbance frequency $A > 60$ Hz have, on average, FR of 190 MW/.1 Hz smaller than events with $A \leq 60$ Hz.

[108] Regressors in the final model have p-values not exceeding 0.1.

Misoperations Analysis

Misoperation Rate by Region and for NERC

Table D.18 lists the operation and misoperation counts and the corresponding misoperation rate by Region and for NERC for the eight quarters available.

Table D.18 Operations and Misoperations by Region from Q4 2012 to Q3 2014

Region	Operations	Misoperations	Misoperation Rate
RF	5839	790	13.53%
SPP	3328	432	12.98%
FRCC	1258	155	12.32%
MRO	2808	307	10.93%
SERC	8499	763	8.98%
TRE	3919	314	8.01%
NPCC	5375	413	7.68%
NERC	**31026**	**3174**	**10.23%**

Figure D.9 illustrates the misoperation rate ranking and summarizes results of the statistical tests on misoperation rate comparison.

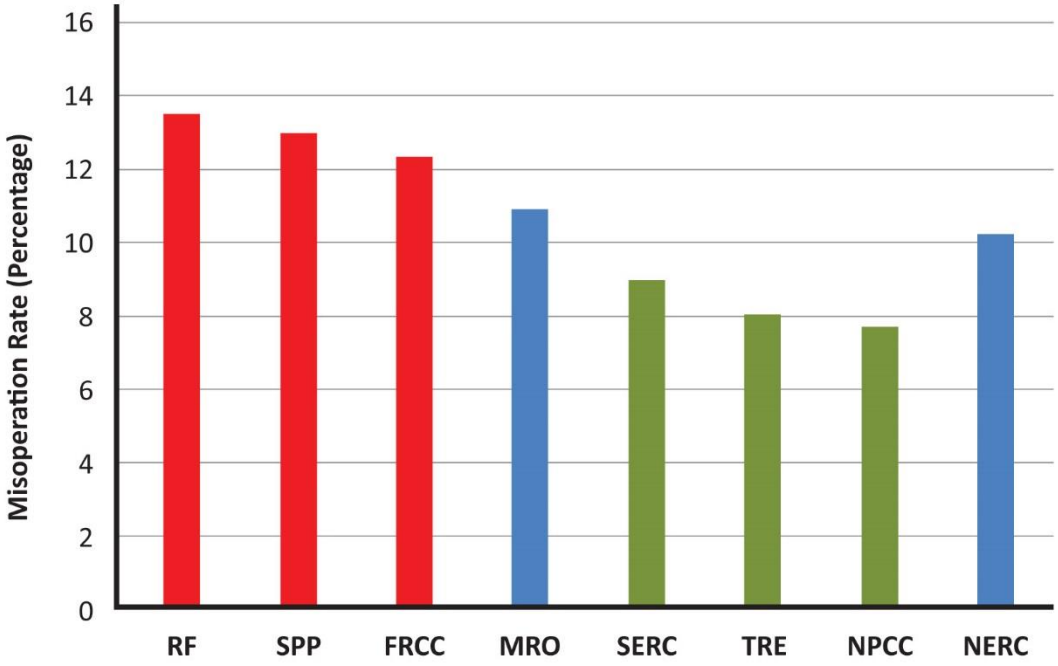


Figure D.9 Two-Year Misoperation Rate by Region (Q4 2012–Q3 2014)

In Figure D.9, red bars show the rates that are statistically significantly higher than NERC's rate, and green bars correspond to the rates significantly lower than NERC's rate. Finally, there is no significant difference between MRO and NERC misoperation rates for the two years.

Comparison of Regional Misoperation Rates

Next, Regional Entity misoperation data was analyzed to find statistically significant differences in misoperation rates between Regions. Table D.19 lists all the pairs of Regions with statistically significant differences in misoperation rate.

Table D.19: Regions with Misoperation Rate Statistically Significantly Different

	Higher	Lower
RFC	none	MRO, SERC, TRE, NPCC
SPP	none	MRO, SERC, TRE, NPCC
FRCC	none	SERC, TRE, NPCC
MRO	RFC, SPP	SERC, TRE, NPCC
SERC	RFC, SPP, FRCC, MRO	NPCC
TRE	RFC, SPP, FRCC, MRO	none
NPCC	RFC, SPP, FRCC, MRO, SERC	none

For example, Table D.19 and Figure D.9 show that the RFC misoperation rate is numerically greater than for any other Region presented. However, there is no significant difference with SPP and FRCC, so Table D.19 lists as statistically significant smaller only rates for MRO, SERC, TRE, and NPCC.

Year-Over-Year Changes by Region

Next, changes from the first four quarters (Q4 2012–Q3 2013, Year 1) to the second four quarters (Q4 2013–Q3 2014, Year 2) were studied to compare time periods with similar composition of seasons. The changes are shown in Figure D.10.

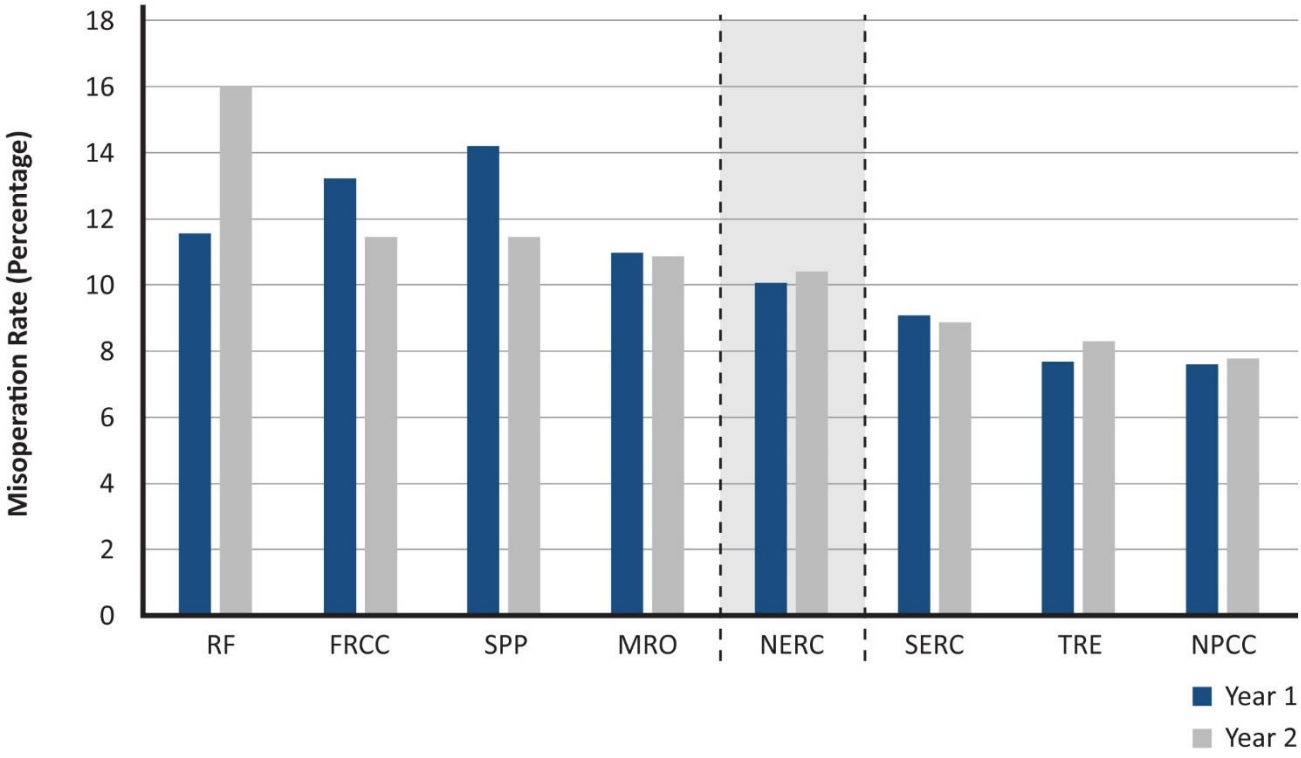


Figure D.10. Year-Over-Year Changes in Misoperation Rate by Region and NERC

By testing the hypotheses on the population proportion, there are only two statistically significant changes in misoperation rate between 2013 and 2014: an increase for the RFC misoperation rate and a decrease for the SPP misoperation rate.

The decrease of misoperations in SPP RE may be due in part to SPP RE's outreach efforts to increase successful protection system operations. SPP RE established a goal of a 92 percent successful operations rate and has made this goal part of the SPP RE staff's performance matrix. SPP RE has presented its misoperation analysis, findings, and conclusions in workshops, SPP RE Trustee meetings, and the monthly newsletter. SPP RE participates in the System Protection and Control Working Group (SPCWG), which completed a white paper on its analysis of Regional Entity relay misoperations caused by communication failures. Communication failures are the primary root cause of misoperations in SPP RE. The SPCWG is working on an additional white paper on misoperations[109] caused by Incorrect Setting/Logic/Design Errors, which is the second-highest root cause of Regional Entity misoperations.

[109] http://www.spp.org/section.asp?group=129&pageID=27

Appendix E – Event Analysis Discussion

Background

The industry's voluntary Event Analysis Process continues to provide valuable information for the ERO and industry to address potential reliability risks or vulnerabilities of the BPS. Since its initial implementation in October of 2010, the process has reported 569 Qualified Events to the ERO and yielded 96 Lessons Learned, including 19 published in 2014.[110] NERC and the Regions assess every Qualified Event to identify causal factors and share with industry the possible risks to reliability. This year, the NERC Cause Code Assignment Process provided greater ability for historical trending and predictive analysis. Industry continued to actively participate in assigning cause codes for events, providing greater transparency on how the ERO analyzes and trends events. This active collaboration is a testament to the importance and effectiveness placed on this area by the industry, and also how important it is for the ERO and industry to truly understand the different contributors to events. The Event Analysis Subcommittee (EAS) has been essential in the maturation of this process and has facilitated the active dissemination of many of the products that have been delivered to date. This chapter highlights some of the significant products that have been produced from this active collaboration.

Bulk Power System Awareness

The first step in the ERO Event Analysis Process is to monitor BPS occurrences above a certain threshold of impact or risk. Bulk Power System Awareness (BPSA) is the process for understanding the potential threats or vulnerabilities to the reliability of the BPS. This starts with understanding occurrences and events in the context in which they occur. NERC's BPSA group and the eight Regional Entities monitor BPS conditions, significant occurrences, and emerging risks and threats across the 14 RCs in North America to maintain an understanding of conditions and situations that could impact the reliable operation of the BPS. The 2014 incoming information consisted of:

- Mandatory reports
  - 500 DOE OE-417 reports
  - 282 EOP-004-2 reports
  - 4 EOP-002-3 reports
- Other information (in no particular order or priority, and not limited to these resources)
  - 1,741 Intelligent Alarms notifications
  - 2,356 FNet notifications and 602 FNet daily summaries
  - 6,172 WECCnet messages
  - 1,691 RCIS messages
  - 186 Space Weather Predictive Center Alerts
  - 1,789 assorted U.S. Government products
  - 3,588 assorted confidential, proprietary or non-public products
  - 13,184 open source media reports
  - 1,257 RC and ISO/RTO notifications

[110] The link to the NERC Lessons Learned page: http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx.

The information gathered allows the ERO to identify and conduct in-depth, critical self-analyses of Qualified Events to identify trends and provide experience-based insight to prevent repeat occurrences. The BPSA group also supports the development and publication of Industry Alerts and awareness products and facilitates information sharing among industry, Regions, and the government during crisis situations and major system disturbances.

- Products:
  - 252 daily reports
  - 33 special reports for significant occurrences
  - 4 security-related NERC Advisory (Level 1) Alerts for ES-ISAC
  - 1 reliability-related NERC Advisory (Level 1) Alert
  - 503 new Event Analysis database entries
  - 170 qualified Event Analysis Process events

Analysis and Reporting of Events

BPS conditions provide recognizable signatures through automated tools, mandatory reports, voluntary information sharing, and third-party publicly available sources. The significant majority of these signatures represent conditions and occurrences that have little or no reliability impact, either positive or adverse, on the BPS. However, being continually cognizant of the short-term condition of the BPS and the signatures associated with the entire range of reliability performance helps the ERO identify significant occurrences and events. Registered entities continue to share information and collaborate with the ERO well beyond what is required to maintain and improve the overall reliability of the grid. Only a small subset of the occurrences of which the BPSA group is made aware rise to the level of a reportable event. When a registered entity experiences an event, the registered entity will recommend an initial category for the event. The categories listed in the Categorization of Events section of the process do not cover all possible events.[111]

The quality, detailed analysis, and investigations that entities have performed have led to quality reports.[112] Good-quality event analysis reports allow for more accurate cause coding of events and has led to better trending. Better trending leads to timely identification of issues being communicated back to the industry.

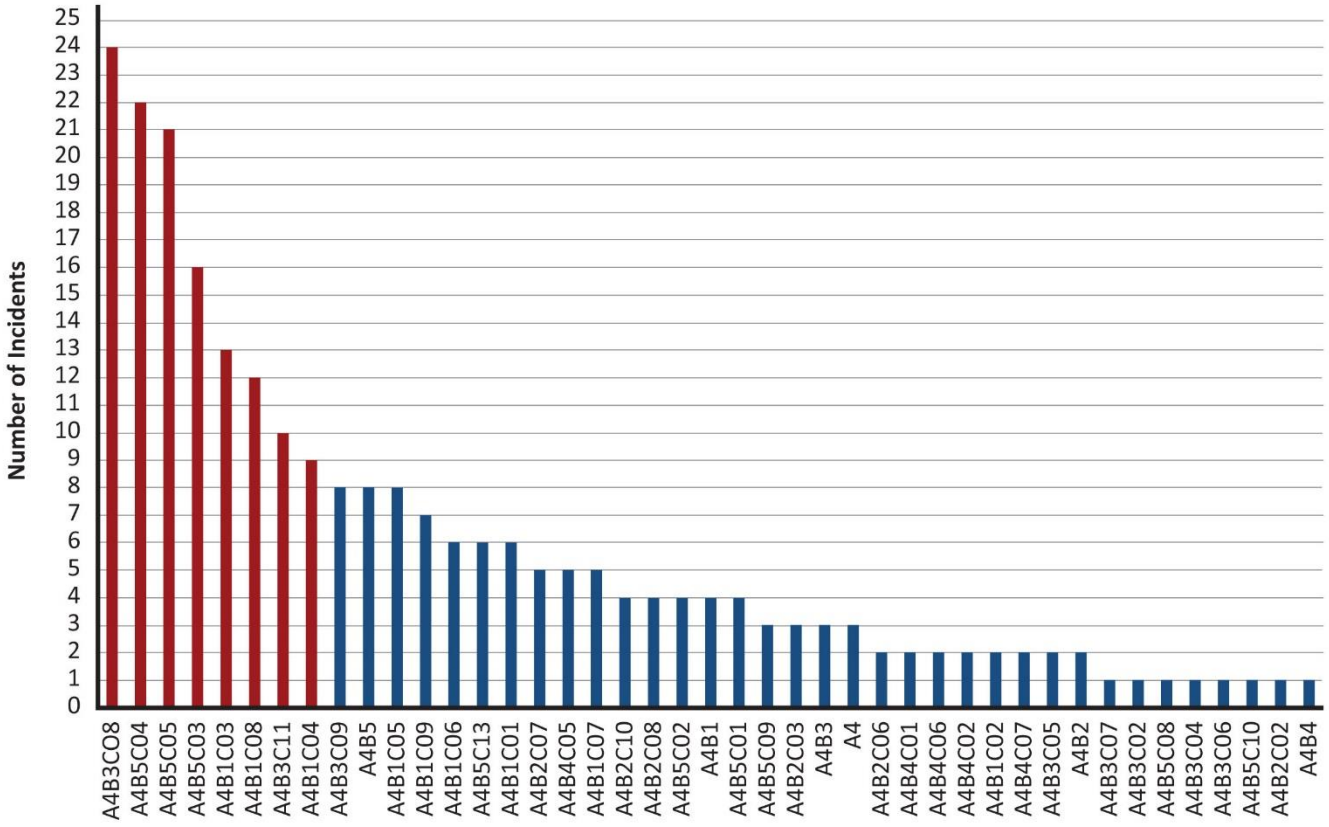
NERC Cause Code Assignment Process

Through the Event Analysis Process, NERC assesses every event report to identify and then share, industry-wide, the apparent threats to reliability that may be emerging. The NERC CCAP manual[113] was updated in March 2014. Cause coding has allowed for easier trending for all event causes. While the root cause of every event can not necessarily be determined, many of the contributing causes or failed defenses can be determined, analyzed, and trended to provide valuable information to the industry. Through the Event Analysis Process, cause codes were assigned to 401 events with 342 contributing cause codes.

A similar identification of trends can be observed in the large contribution of “less than adequate” or “needs improvement” cause factors in the area of Management and Organizational practices that contribute to events. Many of these threats can be identified and shared with the industry for awareness. For example, in Figure E.1 below, the identification of some of the particular challenges to organization and management effectiveness are

[111] For a more thorough review of the process, see: http://www.nerc.com/pa/rrm/ea/EA Program Document Library/Final_ERO_EA_Process_V2.1.pdf.
[112] http://www.nerc.com/pa/rrm/ea/EA Program Document Library/NERC-Report-Quality.pdf
[113] http://www.nerc.com/files/NERC_Cause_Code_Assignment_Process_February_2013.pdf

identified. Management of complex systems and organizations is a challenge in every industry, and the percentage of events with these contributing factors is collectively found in other industries.



A4B3CO8 = Job scoping did not identify special circumstances and/or conditions
A4B5C04 = Risks/consequences associated with change not adequately reviewed
A4B5C05 = System interactions not considered
A4B5C03 = Inadequate vendor support of change
A4B1C03 = Management direction created insufficient awareness of impact of actions on safety/reliability
A4B1C08 = Corrective action responses to a known or repetitive problem was untimely
A4B3C11 = Inadequate work package preparation
A4B1C04 = Management follow-up or monitoring of activities did not identify problems

Figure E.1: Management or Organization Challenges Contributing to an Event

Many of the most frequently identified contributing causes for events seen in Figure E.1 were found in the severe cold weather events. NERC, in close collaboration with Regional Entity staff and industry, published a report titled *Assessment of Previous Severe Winter Weather Reports 1983-2011* to provide a review and comparison of previous winter weather events.[114] This review and a cold weather training package were provided to the industry to assist them with winter weather preparation.

Over 350 owners, users, and operators attended a webinar in October of 2014 that provided the industry reports and training material in preparation for the upcoming winter weather forecasts and entity cold weather preparedness. During the webinar, the impacts from both the February 2011 Southwest Cold Weather Event and previous cold weather events were discussed. The webinar encouraged Generator Owners and Operators to focus

[114] These reports can be found at http://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx .

on areas that were observed in past events, such as inspecting and maintaining heat trace equipment and thermal insulation, erecting adequate wind breaks and enclosures, and taking measures to protect instrument lines and equipment prior to the onset of winter weather.

The *Assessment of Previous Severe Winter Weather Reports 1983-2011* report was also reviewed during the webinar. This was to remind industry that generators experienced weather-related outages, and rolling blackouts in previous events and lessons learned from these events could have prevented outages in more recent winter events.

The Reliability Guideline *Generating Unit Winter Weather Readiness – Current Industry Practices* was also reviewed. This guideline provides a general framework for developing an effective winter weather readiness program for generating units throughout North America. Although the NERC *Winter Reliability Assessment 2014-15* was expected to be published later in November, attendees were given a preview of the draft. The NOAA winter outlook, resource adequacy, and seasonal reliability issues were also covered during the webinar. Attendees were introduced to a *Cold Weather Event Training Package* designed by NERC training staff to assist nontraditional cold weather registered entities with properly preparing for cold weather events. The materials were designed to be a guide to training sessions. These materials have been created as a foundation for training and remain in PowerPoint[115] format to allow for customization based on registered entity needs.

The Event Analysis Process continues to establish the appropriate balance of data reporting for analysis and use by the industry. NERC is investigating ways to sustain positive efforts and to improve the process.

Individual and Organizational Human Performance

Analysis of the event reports to date have identified possible workforce capability and human performance challenges that pose threats to reliability. Workforce capability and human performance is a broad topic and can most simply be divided into management, team, and individual levels. To provide more detailed information on the types of errors that were observed in BPS events since the inception of the NERC Event Analysis program, and specifically events that involved human error or potentially less-than-adequate training, the following summary is provided.

Generally, individual error is classified in the mode of performance in which the individual was operating when the error was committed. The NERC Cause Code Assignment Process uses a popular methodology as prescribed in one of the three modes, depending on the nature of the task and the level of experience with the particular situation. That is, when information is first perceived and interpreted in the processing system, that information is processed cognitively in either the skill-based, knowledge-based, or rule-based levels, depending on the individual's degree of experience with the particular situation.

Additionally, when contributing causes are considered, over half of the event reports to date indicate some management or organizational challenges. To support industry with these challenges, NERC held its third annual HP conference in Atlanta, Improving Human Performance on the Grid,[116] at the end of March 2014. The focus this year was not only on individual human performance, but the organizational and management challenges around human capital. The conference included industry and related industry professionals in the field, with over 200 attendees from all Regions. The conference and associated workshops were very well received. NERC supported WECC for a similar venue for industry in the fall. NERC provided industry support in this area to well over 250 registered entities across the eight Regions.

[115] This webinar presentation can be found at: http://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx.

[116] The full conference presentations for the past Human Performance Conference at NERC can be found at http://www.nerc.com/pa/rrm/hp/Pages/default.aspx.

Monitoring and Situation Awareness (Real-Time Tools)

Energy Management Systems (EMS), including SCADA, digital, or analog communications and real time tools, are vital for maintaining situational awareness and making operating decisions at both the individual and the organizational level. EMS systems are extremely reliable and are typically redundant. However, an outage of the EMS system increases the potential risk to the reliability of the BPS. The NERC Event Analysis program has received 111 Category 2b event reports, where a complete loss of SCADA, monitoring, or control has lasted for more than 30 minutes. NERC's commitment to active collaboration and sharing has allowed more information to be adequately reviewed and shared about these events in conjunction with the NERC Regions and the affected entities. In October 2013, the Event Analysis Process changed to add a new category of events.

Category 1h, for the partial loss of EMS, is defined as:

> *Loss of monitoring or control, at a control center, such that it significantly affects the entity's ability to make operating decisions for 30 continuous minutes or more.*

Examples include but are not limited to the following:

1. Loss of operator ability to remotely monitor, control BES Elements, or both
2. Loss of communications from SCADA RTUs
3. Unavailability of ICCP links reducing BES visibility
4. Loss of the ability to remotely monitor and control generating units via AGC
5. Unacceptable State Estimator or Contingency Analysis solutions

The EAS transitioned the Energy Management System Task Force (EMSTF) to a permanent working group to analyze the events and data that were being collected about EMS outages and challenges. Industry also recognized that many EMS outages were significantly less than the Category 2b, but impacted the decision-making activities for which the EMS is used. Category 1h was created to learn more about these type of events. This category allows the EMSWG to collect a greater number of the occurrences of EMS partial outages and share this information with the industry. With this modification of reporting EMS events, the number of Category 1h events reported by the industry has provided useful information and has decreased the number of Category 2b events. The active participation has led to even more detailed reporting and sharing of information, all helping the industry understand and mitigate the risk of these events.

From the Event Analysis reports and the work of the EAS, NERC published multiple lessons learned specifically about EMS outages and worked to build and support an industry-led EMSTF to support the EAS. The hard work and active sharing of this group has reduced some of the residual risk associated with this potential loss of situation awareness and monitoring capability associated with this type of event, and will continue to provide valuable information to the industry.

With the support of the EMSTF, NERC hosted its second *Monitoring and Situational Awareness Conference*, focused on improving Energy Management Systems reliability, September 23–24, 2014. The conference brought together more than 90 Operations and EMS experts from more than 55 registered entities, and a variety of vendors and consultants. The entities that attended came from across all of the Regions and Canada.

The feedback from participants has been extremely positive for the two conferences. Attendees liked the technical nature of the presentations and the takeaways they could use to improve the processes and procedures at their own companies. The openness with which the EMS issues and their corrective actions were shared was greatly appreciated by the attendees. Also appreciated was the platform that NERC provided to transparently share the events and learn from them. A third workshop was requested by industry for 2015. Industry has demonstrated

appropriate responses to EMS outages, and the ERO can now more accurately assess the residual risk to the BPS from EMS outages.[117] Industry has expressed continued strong interest and support for these information-sharing venues.

Event SRI (eSRI)

NERC Event Analysis staff calculates an Event Severity Risk Index (eSRI) for all qualified events (as defined in the Event Analysis Process).[118] This calculation is based on the methodology used by NERC for the standard Severity Risk Index (SRI) as described in Chapter 3, and considers the loss of transmission, the loss of generation, and the loss of firm load (along with load-loss duration).

Every event reported through the Event Analysis Process has its eSRI calculated, but for the purposes of trending, certain event groups are excluded. The excluded groups are:

1. Weather-driven events;
2. AESO-islanding events; and
3. Category 4-5 events.

The purpose of excluding Category 4–5 events is that they are monitored and tracked in a distinct manner, so counting them in this trending would be duplicative. As AESO designed islanding as an intentional act in their SPS schemes, these are also excluded. The purpose of excluding the weather-driven events is because they are outside of the control of the BES entities, thus not considered when studying impact over which there is control. A weather-driven event is an event whose root cause is determined to be weather (or other force of nature); examples would include the Hurricane Sandy event, an earthquake, or a string of tornadoes knocking down transmission towers, among others. There have been 14 of these events since October 2010, when the current Event Analysis Process was developed.

For the events reported since October 2010, the total number of events was 568; of these, 29 were AESO islanding, 14 were weather-driven, and five (three of which are also weather-driven) were Category 4–5 events. This means only two Category 4–5 events were excluded as Category 4–5 events, while three of them were excluded as weather-driven events. The total number of events for which eSRI will be included in any trending is 523 events (out of the total of 568).

The formula used is:

$eSRI = RPL * W_L * (MW_L) + W_T * (N_T) + W_G * (N_G)$, where

RPL = Load Restoration Promptness Level,
W_L = Weighting of load loss (60%),
MW_L = normalized weighting of load loss,
W_T = weighting of transmission lines lost (30%),
N_T = normalized number of transmission lines lost, in percent,
W_G = weighting of loss generation (10%),
N_G = normalized Net Dependable Capacity of generation lost.

The value of this calculation results in a number between zero (0) and one (1); thus, for easier use in analysis, this small number is multiplied by 1000.

[117] The full conference presentations for the past Monitoring and Situation Awareness conferences can be found at http://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx.

[118] http://www.nerc.com/pa/rrm/ea/EA Program Document Library/Final_ERO_EA_Process_V2.1.pdf

Once this number is calculated for each event and is plotted in chronological sequence, the slope of the trend line is calculated and plotted. In this way, the trend can be visually identified (as well as numerically calculated using statistical software). Every day has its eSRI calculated (meaning a day with no events has an eSRI = 0.000). For any days with multiple events, the eSRIs are additive.

Summary

The Event Analysis Process continues to provide valuable information for the industry to address potential threats or vulnerabilities to the reliability of the BPS. This continued active collaboration remains a testament to how much effort and resources are being expended in this area by the industry as well as how important it is for the ERO and industry to truly understand the different contributors to events. The continued cooperation and collaboration with the industry is the hallmark to this program's success.

The ability to identify specific pieces of equipment that are potential threats, as well as emerging trends that increase risk to the system, illustrates the value of the Event Analysis Process. These outcomes, coupled with the ability to actively share the information through Lessons Learned, webinars, technical conferences, and related venues, remain critical to the sustainment of high reliability.

Appendix F – Statistical Summary of SRI Assessment

The PAS has investigated the SRI performance for 2010 through 2014 as well as a year-by-year comparison and seasonal changes. A statistical test indicated statistically significant changes among annual SRI. ANOVA analysis showed that 2011 performance was the best SRI since 2010; moreover, the difference in all other years was statistically significant.[119] The 2014 SRI performance was statistically similar to 2010 and 2012 but worse than 2011 and 2013. The descriptive statistics of annual SRI are listed in Table F.1.

Table F.1: Descriptive Statistics of Annual SRI

Year	N	Mean	Standard Deviation	Minimum	Maximum	Median
2010	365	1.74	0.61	0.59	4.64	1.70
2011	365	1.50	1.04	0.48	13.97	1.34
2012	366	1.78	0.81	0.55	8.87	1.65
2013	365	1.67	0.60	0.46	4.06	1.57
2014	365	1.85	0.87	11.14	11.14	1.72

[119] ANOVA with Fisher's least significant difference test at the significant level 0.05.

The relative SRI performance by year is further visible in Figure F.1. The year 2011 was the best as measured by a median as well as a mean, in spite of the relatively large standard deviation (whose outliers included the September 8, 2011, load shed event, in addition to the February 2, 2011, cold weather load loss event).

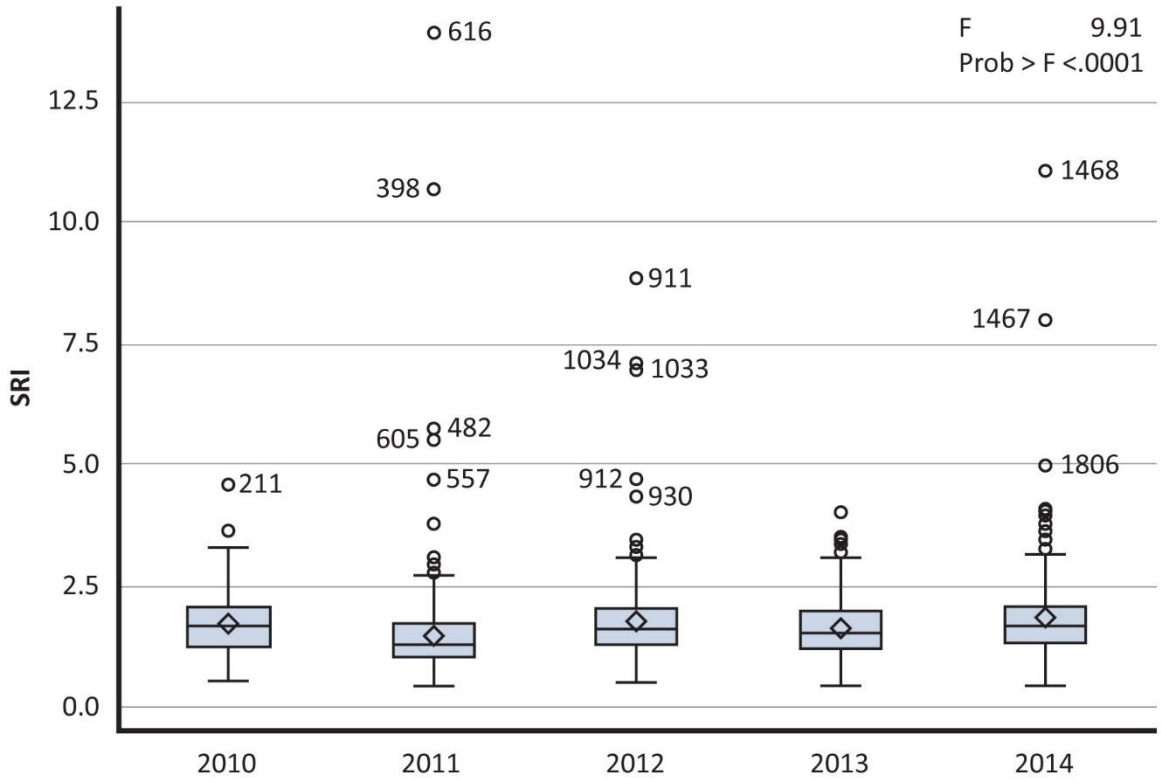


Figure F.1: Boxplot of Annual SRI

The performance of each year compared to every other year is depicted in Table F.2 below; if no reference to statistical significance is made within the table, it is assumed to be statistically significant.[120]

Table F.2: Pairwise Comparison of Annual SRI

	Compared to Year			
Base Year	**2011**	**2012**	**2013**	**2014**
2010	2011 Better	No Statistically Significant Difference	No Statistically Significant Difference	No Statistically Significant Difference
2011		2011 Better	2011 Better	2011 Better
2012			No Statistically Significant Difference	No Statistically Significant Difference
2013				2013 Better

[120] At significance level 0.05.

In Figure F.2, the trend of performance is shown over the five-year history along with a time trend line.

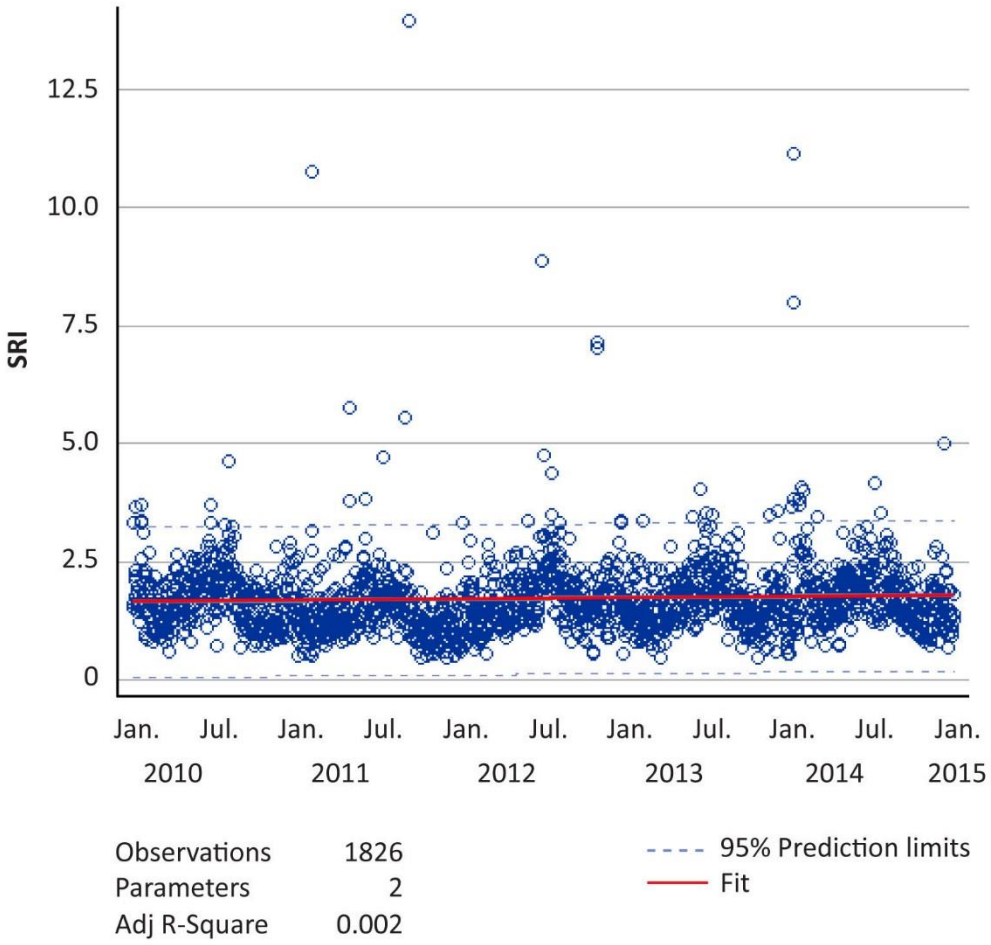


Figure F.2: Fit Plot for SRI 2010–2014

The time trend line has a statistically significant positive slope (p = 0.032). The same result can be drawn for the correlations analysis: on average, the trend line for SRI is increasing over time (i.e., the hypothesis on a stable performance SRI over 2010 to 2014 cannot be accepted at 0.05 significance level).

Finally, the statistical analysis of the seasonal performance was done. It revealed statistically significant differences in SRI by season. The fall SRI has the best performance, the summer SRI has the worst. Table F.3 shows the statistics by season based on the 2010 to 2014 data.

Table F.3: Descriptive Statistics of SRI by Season

Season	N	SRI	
		Mean	Standard Deviation
Winter	452	1.66	0.97
Spring	460	1.66	0.55
Summer	460	2.05	0.71
Fall	454	1.47	0.84

A statistical test[121] indicated that all differences in the seasonal expected SRI are statistically significant except those for winter and spring, which is also illustrated in Figure F.3.

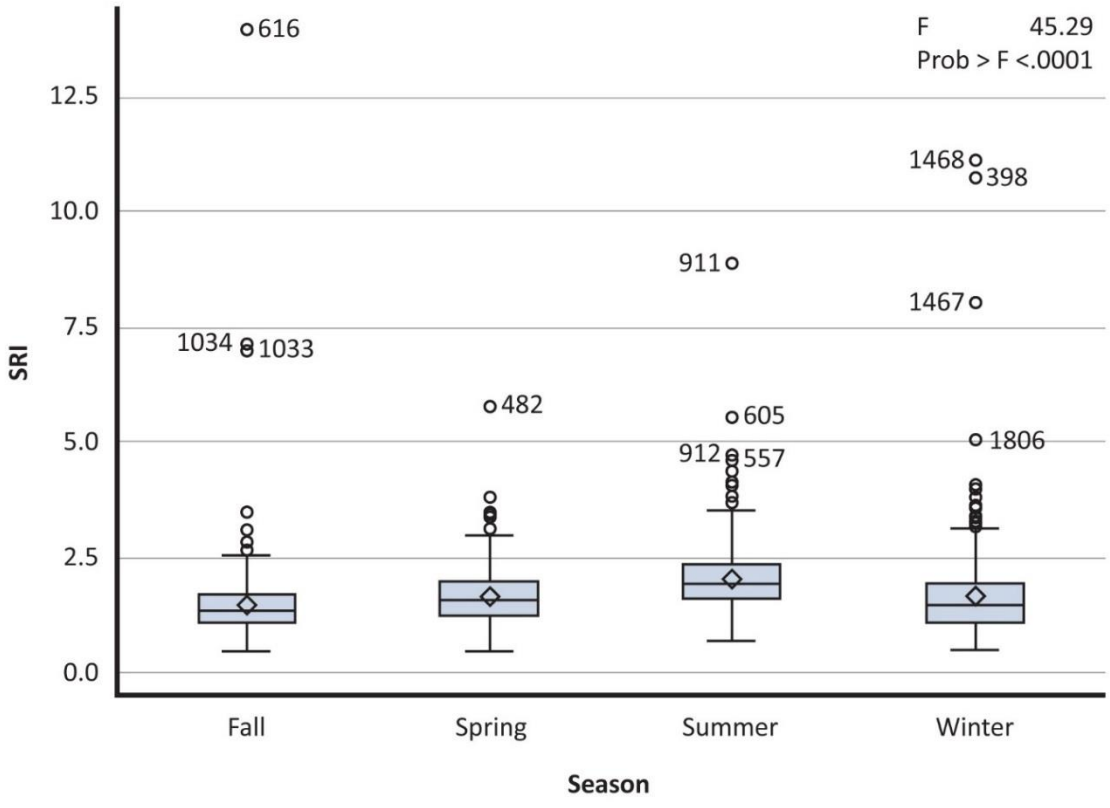


Figure F.3: Boxplot for SRI by Season 2010–2014

[121]ANOVA with Fisher's least significant difference test at the significant level 0.05.

Appendix G – Abbreviations Used in This Report

Acronym	Description
ALR	Adequate Level of Reliability
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Common/Dependent Mode
EEA	Energy Emergency Alert
ERO	Electric Reliability Organization
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
ICC	Initiating Cause Code
IROL	Interconnection Reliability Operating Limit
ISO	Independent System Operator
ISO-NE	ISO New England
KCMI	Key Compliance Monitoring Index
MRO	Midwest Reliability Organization
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent Service Operator
PAS	Performance Analysis Subcommittee
PSMTF	Protection System Misoperation Task Force
RC	Reliability Coordinator
RE	Regional Entities
RF	ReliabilityFirst
RSG	Reserve-Sharing Group
SERC	SERC Reliability Corporation
SNL	Sandia National Laboratories
SOL	System Operating Limit
SPS	Special Protection Schemes
SPCS	System Protection and Control Subcommittee
SPP	Southwest Power Pool
SRI	Severity Risk Index
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TO	Transmission Owner
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Appendix H – Contributions

Acknowledgements

NERC would like to express its appreciation to the many people who provided technical support and identified areas for improvement.

NERC Industry Groups

Table H.1 lists the NERC industry group contributors.

Table H.1: NERC Group Acknowledgements

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Frequency Working Group	Chair: Sydney Niemeyer, NRG Energy
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Planning Committee	Chair: Dave Weaver, Exelon Corporation Vice Chair: Brian Evans-Mongeon, Utility Services, Inc.
Reliability Assessment Subcommittee	Chair: Layne Brown, WECC
System Protection and Control Subcommittee	Chair: William J. Miller, Exelon Corporation Vice Chair: Philip B. Winston, Southern Company
Protection System Misoperations Task Force	Chair: John Seidel, Midwest Reliability Organization
Spare Equipment Working Group	Vice Chair: Puesh Kumar, APPA
Compliance and Certification Committee	Chair: Patricia E. Metro, National Rural Electric Cooperative Association Vice Chair: Jennifer Flandermeyer, KCP&L

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Table H.2 provides a list of the Regional Entity staff that provided data and content review.

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Media Release

Report Shows Strong Performance, Stable Frequency Response and Less Severe Transmission Outages

May 28, 2015

ATLANTA – The North American Electric Reliability Corporation completed an independent review of bulk power system trends to analyze the state of reliability and provide an integrated view of reliability performance in its annual *State of Reliability 2015*. The report's key findings show the bulk power system sustained high reliability performance, realized a reduction in unplanned transmission outages leading to load loss, maintained stable frequency response, and experienced no instances of load loss due to a cyber or physical security risk. Consistent with prior *State of Reliability* report findings, uncontrollable severe weather events continue to be the largest factor affecting the performance of the bulk power system.

The *State of Reliability 2015* report's findings and recommendations serve as input to NERC's risk assessment and reliability standards project prioritization of specific actions that can be taken to manage potential risks and enhance bulk power system reliability.

"The data collected and analyzed for this report shows a continuing trend of bulk power system equipment owners and operators achieving the desired reliability objectives," said Howard Gugel, NERC director of Performance Analysis. "While the performance of the bulk power system remains strong, NERC continues to work with industry to enhance reliability the grid."

NERC incorporated cyber and physical security metrics as key reliability indicators analyzed this year to set a baseline on critical infrastructure protection. Two of the metrics examined security incidents reported to NERC and the Department of Energy in 2014 and found that cyber and physical security protections effectively prevented loss of load due to these incidents.

Other key findings include:

- Severe weather events, which resulted in generator outages and deratings, remained a significant threat to reliability. Looking at the 10 most severe weather events in 2014, there were three days when periods of high stress

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occurred on the bulk power system — two days during the January polar vortex event and another day during severe windstorms in California in December.

- Frequency response, which helps generators maintain reliability by adjusting output to meet system demand for electricity, remained above recommended interconnection obligation levels for the third consecutive year. NERC conducts annual tests to determine whether Interconnection Frequency Response Obligations are met in the Eastern Interconnection, the Western Interconnection, the Electric Reliability Council of Texas Interconnection and the Québec Interconnection.

- Unplanned transmission outages affecting on the bulk power system causing loss of load dropped from six in 2013 to three in 2014 — down from an average of 10 unplanned transmission outages between 2002 and 2011. While the total number of unplanned transmission outages impacting the bulk power system declined from 2013 to 2014, misoperations and equipment failure remained the greatest contributors to those outages, excluding weather.

- In 2014, there were four Energy Emergency Alert Level 3 events declared, which is less than any other year for which data was reported. Of the four events declared, only one resulted in load shedding. This event was due to conditions during the January polar vortex.

The *State of Reliability 2015* highlights key recommendations for stakeholders going forward that include:

- Developing metrics that provide insight into weather impacts on bulk power system performance, especially during load-loss events.
- Determining whether additional actions are required to maintain and improve frequency response performance.
- Evaluating the failure rate of circuit breakers and determine the impact of bus configuration on ac transmission circuit outages.
- Working with the Protection System Misoperations Task Force to develop a guideline on quality control to improve protective relay settings and developing an industry outreach program on reducing protection system misoperation.

###

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: TBD

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SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted. Such functional classes[1] include: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, market operators, Planning Authorities, Transmission Planners, Resource Planners, Load-Serving Entities, and Distribution Providers. Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance**— Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance**— The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** —Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome**— Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations**— Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments or revisions to the *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

    3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

    3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment or apply to change Segments at any time.

    3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments at least every three years to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to

belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC shall assign a standards process manager to administer the development of continent-wide Reliability Standards and a regional standards manager to administer the development of Regional Reliability Standards. The standards process manager shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual*. The standards process manager and the regional standards manager shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. The regional standards manager shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC or directs NERC to develop a Reliability Standard, NERC shall within five (5) business days notify all other Applicable Governmental Authorities, and shall within thirty (30) calendar days report to all Applicable Governmental Authorities

a plan and timetable for modification or development of the Reliability Standard. Reliability Standards that are remanded or directed by an Applicable Governmental Authority shall be modified or developed using the *Standard Processes Manual*. NERC shall, during the development of a modification for the remanded Reliability Standard or directed Reliability Standard, consult with other Applicable Governmental Authorities to coordinate any impacts of the proposed Reliability Standards in those other jurisdictions. The expedited standards development process may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authorities, respecting to the extent possible the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the expedited action process described in the *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

   3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

      3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

      3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material

interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard, due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

    3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

    3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability

Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory

within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or regional Variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — NERC shall maintain a current catalog of Regional Criteria. Regional Entities shall provide a catalog listing of Regional Criteria to NERC and shall notify NERC of changes to the listing. Regional Entities shall provide any listed document to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the

governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Accreditation

NERC shall seek and maintain accreditation of the NERC Reliability Standards development process by the American National Standards Institute.

317. Five-Year Review of Reliability Standards

NERC shall complete a review of each NERC Reliability Standard at least once every five years, or such longer period as is permitted by the American National Standards Institute, from the effective date of the Reliability Standard or the latest revision to the Reliability Standard, whichever is later. The review process shall be conducted in accordance with the NERC *Standard Processes Manual*. The standards process manager shall be responsible for administration of the five-year review of Reliability Standards. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely

as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC standards information manager of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the *Standard Processes Manual*, **Appendix 3A** to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities. If the Board of Trustees is presented with a proposed Reliability Standard that fails to address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a

timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; and (iii) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

   2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

   2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

   4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in

the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

5.5 A Reliability Standard approved under paragraph 5 of this Rule shall not be eligible for submission as an American National Standard.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

SECTION 400 — COMPLIANCE ENFORCEMENT

401. Scope of the NERC Compliance Monitoring and Enforcement Program

1. **Components of the NERC Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a NERC Compliance Monitoring and Enforcement Program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC that has been approved by the Applicable Governmental Authority) has been given enforcement authority. There are four distinct parts of the NERC Compliance Monitoring and Enforcement Program: (1) NERC's oversight of the Regional Entity Compliance Monitoring and Enforcement Programs (Section 402), (2) the definition of the required Regional Entity Compliance Monitoring and Enforcement Program attributes (Section 403), (3) NERC's monitoring of Regional Entity compliance with Reliability Standards (Section 404), and (4) the monitoring of compliance with Reliability Standards that are applicable to NERC (Sections 405–406).

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users, Regional Entities, and NERC, are required to comply with all approved NERC Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered NERC Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards and compliance reporting procedures.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer a Regional Entity Compliance Monitoring and Enforcement program to meet the NERC Compliance Monitoring and Enforcement Program goals and the requirements in this Section 400.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity in the event that NERC does not have a delegation agreement, or the Regional Entity withdraws from the agreement or does not operate its Compliance Monitoring and Enforcement Program in accordance with the delegation agreement or other applicable requirements.

5.1 Should NERC not have a delegation agreement with a Regional Entity covering a geographic area, or a Regional Entity withdraws from an existing delegation agreement or the delegation agreement is otherwise terminated, NERC will directly administer the Compliance Monitoring and Enforcement Program applicable to owners, operators and users of the Bulk Power System within that geographic area.

1. This monitoring and enforcement will be accomplished by NERC and Compliance Staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant compliance information regarding Registered Entities, contacts, prior compliance information and actions, Mitigation Plans, and Remedial Action Directives for the period in which the Regional Entity was responsible for administering the Compliance Monitoring and Enforcement Program.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies collected to offset the expenses of administering the Compliance Monitoring and Enforcement Program for the geographic area.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the Compliance Monitoring and Enforcement Program within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. ~~**Actively Monitored Requirements**~~**Risk Elements** — NERC, with input from the Regional entities, stakeholders, and regulators, shall at least annually ~~select a subset of the~~identify risk elements to prioritize risks to the reliability of the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements are to be ~~actively monitored and audited~~considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan. NERC identifies the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. NERC uses these risk elements to identify and prioritize interconnection and continent-wide risks to the reliability of the Bulk Power System. These identified risks, as well as risks to the reliability of the Bulk Power System identified by Regional Entities for their footprint, represent the focus for monitoring activities in the upcoming year, and become inputs for developing oversight plans for individual Registered Entities. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable NERC Reliability Standards whether or not they

are ~~included in the subset of Reliability Standards and Requirements designated~~identified as areas of focus to be ~~actively monitored and~~considered for compliance oversight ~~audited~~ in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which is incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC shall maintain a record of each compliance submission, including Self-Reported, Possible, Alleged, and Confirmed Violations of approved Reliability Standards; associated Penalties, sanctions, Remedial Action Directives and settlements; and the status of mitigation actions.

10. **Confidential Information** — NERC will treat all Possible and Alleged Violations of Reliability Standards and matters related to a Compliance Monitoring and Enforcement Program process, including the status of any Compliance Investigation or other Compliance Monitoring and Enforcement Program process, as confidential in accordance with Section 1500.

    The types of information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500. Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident, will be identified and protected from public disclosure as Critical Energy Infrastructure Information in accordance with Section 1500.

    The Regional Entity and NERC shall give Bulk Power System owners, operators, and users a reasonable opportunity to demonstrate that information concerning a violation is confidential before such report is disclosed to the public.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with a Possible or Alleged Violation(s) of a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a Possible or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC shall, subject to the confidentiality requirements of these Rules of Procedure, publicly post each Confirmed Violation, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation report, on its website.

11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the Confirmed Violation or report to be posted publicly. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

11.2 In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information (*NERC Security Guidelines for the Electricity Sector — Protecting Potentially Sensitive Information* may be used as a guide) or other Confidential Information shall be redacted in accordance with Section 1500 and not be released publicly.

11.3 Subject to redaction of Critical Energy Infrastructure Information or other Confidential Information, for each Confirmed Violation or settlement relating to a Possible Violation or an Alleged Violation, the public posting shall include the name of any relevant entity, the nature, time period, and circumstances of such Possible, Alleged or Confirmed Violation, any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity in connection with the Confirmed Violation or settlement, and sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Violation Information Review** — NERC Compliance Staff shall periodically review and analyze all reports of Possible, Alleged and Confirmed Violations to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs

1. **NERC Monitoring Program** — NERC shall have a program to monitor the Compliance Monitoring and Enforcement Program of each Regional Entity that has been delegated authority. The objective of this monitoring program shall be to ensure that the Regional Entity carries out its Compliance Monitoring and Enforcement Program in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's Compliance Monitoring and Enforcement Program. Oversight and monitoring by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, and regular evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance as described below.

1.1 **NERC Review of Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans** — NERC shall require each Regional Entity to submit for review and approval an annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan. NERC shall review each annual Regional Entity

Compliance Monitoring and Enforcement Program Implementation Plan and shall accept the plan if it meets NERC requirements and the requirements of the delegation agreement.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity Compliance Monitoring and Enforcement Program implements the NERC Compliance Monitoring and Enforcement Program. The evaluation shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreement, directives in effect pursuant to the delegation agreement, approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans, required Compliance Monitoring and Enforcement Program attributes, and the NERC Compliance Monitoring and Enforcement Program procedures. These evaluations shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 3.1.6 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity Compliance Monitoring and Enforcement Program. The current procedure is contained in the NERC Audit of Regional Entity Compliance Programs, which is incorporated into these rules as **Appendix 4A**.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's

Compliance Monitoring and Enforcement Program. A representative of the Regional Entity being audited will be allowed to participate in the audit as an observer.

2. **Consistency Among Regional Compliance Monitoring and Enforcement Programs** — To provide for a consistent Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program, which is incorporated into these rules of procedure as **Appendix 4C**. Any differences in Regional Entity Compliance Monitoring and Enforcement Program methods, including determination of violations and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

   2.1 NERC shall ensure that each of the Regional Entity Compliance Monitoring and Enforcement Programs meets these Rules of Procedure, including **Appendix 4C**, and follows the terms of the delegation agreement and the approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan.

   2.2 NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program in **Appendix 4C** containing the procedures to ensure the consistency and fairness of the processes used to determine Regional Entity Compliance Monitoring and Enforcement Program findings of compliance and noncompliance, and the application of Penalties and sanctions.

   2.3 NERC shall periodically conduct Regional Entity compliance manager forums. These forums shall use the results of Regional Entity Compliance Monitoring and Enforcement Program audits and findings of NERC Compliance Staff to identify and refine Regional Entity Compliance Monitoring and Enforcement Program differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Violation Disclosure** — NERC shall disclose all Confirmed Violations and maintain as confidential Possible Violations and Alleged Violations, according to the reporting and disclosure process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — NERC and Regional Entity Compliance Staff shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties

and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Regional Entity boards or a compliance panel reporting directly to the Regional Entity board will be vested with the authority for the overall Regional Entity Compliance Monitoring and Enforcement Program and have the authority to impose Penalties and sanctions on behalf of NERC, where authorized by applicable legislation or agreement. Remedial Action Directives may be issued by NERC or a Regional Entity that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert a violation of a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections 408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

   The appeals process will also allow for appeals to NERC of any findings of noncompliance issued by NERC to a Regional Entity for Reliability Standards and Requirements where the Regional Entity is monitored for compliance to a Reliability Standard. No monetary Penalties will be levied in these matters; however sanctions, remedial actions, and directives to comply may be applied by NERC.

7. **Conflict Disclosure** — NERC shall disclose to the appropriate governmental authorities any potential conflicts between a market rule and the enforcement of a Regional Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the NERC Compliance Monitoring and Enforcement Program, NERC and Regional Entity staff, Compliance Audit team members, and committee members shall maintain the confidentiality of information obtained and shared during compliance monitoring and enforcement processes including Compliance Investigations, Compliance Audits, Spot Checks, drafting of reports, appeals, and closed meetings.

   8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for staff and other Compliance Monitoring and Enforcement Program participants.

8.2 Individuals not bound by NERC or Regional Entity codes of conduct who serve on compliance-related committees or Compliance Audit teams shall sign a NERC confidentiality agreement prior to participating on the committee or Compliance Audit team.

8.3 Information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall not be distributed outside of a committee or team, nor released publicly. Other information subject to confidentiality is identified in Section 1500.

8.4 In the event that a staff, committee, or Compliance Audit team member violates any of the confidentiality rules set forth above, the staff, committee, or Compliance Audit team member and any member organization with which the individual is associated may be subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future Compliance Monitoring and Enforcement Program activities.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to all people who participate in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs

Each Regional Entity Compliance Monitoring and Enforcement Program shall promote excellence in the enforcement of Reliability Standards. To accomplish this goal, each Regional Entity Compliance Monitoring and Enforcement Program shall (i) conform to and comply with the NERC uniform Compliance Monitoring and Enforcement Program, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its Compliance Monitoring and Enforcement Program shall exhibit independence, meaning the Compliance Monitoring and Enforcement Program shall be organized so that its compliance monitoring and enforcement activities are carried out separately from other activities of the Regional Entity. The Compliance Monitoring and Enforcement Program shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored or other Regional Entity activities that are required to meet the Reliability Standards. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity Compliance Monitoring and Enforcement Program shall exercise the responsibility and authority in carrying out the delegated functions of the NERC Compliance Monitoring and Enforcement Program in accordance with delegation agreements and **Appendix 4C**. These functions include but are not limited to: data gathering, data reporting, Compliance Investigations, Compliance Audit activities, evaluating compliance and noncompliance, imposing Penalties and sanctions, and approving and tracking mitigation actions.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the NERC Compliance Monitoring and Enforcement Program, a Regional Entity shall not sub-delegate its Compliance Monitoring and Enforcement Program duties to entities or persons other than the Regional Entity Compliance Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** The Regional Entity board or compliance panel reporting directly to the Regional Entity board (with appropriate recusal procedures) will be vested with the authority for conducting compliance hearings in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single segment may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Compliance Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the Regional Entity Compliance Monitoring and Enforcement Program.

6. **Regional Entity Compliance Staff Independence** — The Regional Entity Compliance Staff shall be capable of and required to make all determinations of compliance and noncompliance and determine Penalties, sanctions, and Remedial Action Directives and to review and accept Mitigation Plans and other Mitigating Activities.

    6.1 Regional Entity Compliance Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

    6.2 Regional Entity Compliance Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement

processes (with the input of industry subject matter experts), make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

6.3 Regional Entity Compliance Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

6.4 Regional Entity Compliance Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure, the NERC delegation agreement and other confidentiality agreements required by the NERC Compliance Monitoring and Enforcement Program.

6.5 Contracting with independent consultants or others working for the Regional Entity Compliance Monitoring and Enforcement Program shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals for the purpose of these Rules of Procedure shall be considered as augmenting Regional Entity Compliance Staff.

7. Use of Industry Subject Matter Experts and Regional Entity Members — Industry experts and Regional Entity members may be called upon to provide their technical expertise in Compliance Monitoring and Enforcement Program activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity Compliance Staff so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than the Compliance Staff of the Regional Entity. Industry subject matter experts, Regional Entity members, or

Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Regional Entity Compliance Monitoring and Enforcement Program Content** — All approved Reliability Standards shall be included in the Regional Entity Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users within the defined boundaries of the Regional Entity. Compliance to approved Regional Reliability Standards is applicable only within the Region of the Regional Entity that submitted those particular Regional Reliability Standards for approval. NERC will identify the risk elements and related ~~minimum set of~~ Reliability Standards and Requirements to be ~~actively monitored~~considered by the Regional Entity in a given year in developing oversight plans for individual Registered Entities.

9. **Antitrust Provisions** — Each Regional Entity's Compliance Monitoring and Enforcement Program shall be structured and administered to abide by U.S. antitrust law and Canadian competition law.

10. **Information Submittal** — All Bulk Power System owners, operators, and users within the Regional Entity responsible for complying with Reliability Standards shall submit timely and accurate information when requested by the Regional Entity or NERC. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

10.1 Each Regional Entity has the authority to collect the necessary information to determine compliance and shall develop processes for gathering data from the Bulk Power System owners, operators, and users the Regional Entity monitors.

10.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.10 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

10.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

10.4 Regional Entities shall notify NERC of all Possible, Alleged and Confirmed Violations of NERC Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

10.5 A Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan with a timeline addressing how the noncompliance will be corrected, unless an enforcement process is used that does not require a Mitigation Plan. The Regional Entity Compliance Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

10.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all compliance data Self-Reported to the Regional Entity Compliance Monitoring and Enforcement Program.

10.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

11. **Compliance Audits of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program of proactive Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**. A Compliance Audit is a process in which a detailed review of the activities of a Bulk Power System owner, operator, or user is performed to determine if that Bulk Power System owner, operator, or user is complying with approved Reliability Standards.

11.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, Compliance Audits shall be performed on a schedule established by NERC.

11.2 Compliance Audits of Balancing Authorities, Reliability Coordinators, and Transmission Operators will include a component at the audited entity's site. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, the Compliance Audit may be either an on-site Compliance Audit or based on review of documents, as determined to be necessary and appropriate by NERC or Regional Entity Compliance Staff.

11.3 Compliance Audits must include a detailed review of the activities of the Bulk Power System owner, operator, or user to determine if the Bulk Power System owner, operator, or user is complying with all approved Reliability Standards identified for audit by NERC. The Compliance Audit shall include a review of supporting documentation and evidence used by the Bulk Power System owner, operator or user to demonstrate compliance for an appropriate period prior to the Compliance Audit.

12. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and information obtained from such processes, are to be non-public and treated as confidential in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis, provided, that NERC and the Regional Entities shall publish (i) schedules of Compliance Audits scheduled in each year, (ii) a public report of each Compliance Audit, and (iii) Notices of Penalty and settlement agreements. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as specific allegations or conclusions regarding Possible or Alleged Violations of Reliability Standards are not included in such disclosures.

13. **Critical Energy Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will be identified and protected from public disclosure as Critical Energy Infrastructure Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

14. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing

with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

15. **Regional Entity Hearing Process** — Each Regional Entity Compliance Monitoring and Enforcement Program shall establish and maintain a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The Regional Entity hearing process shall be conducted before the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. The Regional Entity hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single segment may veto any matter brought before the Hearing Body after recusals.

    Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

    If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity hearing process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

16. **Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan** — Each Regional Entity shall annually develop and submit to NERC for approval a Regional Entity Compliance Monitoring and Enforcement Implementation Plan in accordance with **Appendix 4C** that, includes details on r~~R~~egional r~~R~~isk a~~A~~ssessment processes and results, Reliability Standards and Requirements associated with r~~R~~egional ~~R~~risk a~~A~~ssessment results, the methods to be used by the Regional Entity for reporting, monitoring, evaluati~~on~~ng, and assess~~ment of~~ ing performance criteria~~,~~ and the Regional Entity's Annual Audit Plan.~~identifies the Reliability Standards and Requirements to be actively monitored (both those required by NERC and any additional Reliability Standards the Regional Entity proposes to monitor), and how each NERC and Regional Entity identified Reliability Standard will be monitored,~~

~~evaluated, reported, sanctioned, and appealed.~~ These Regional Implementation Plans will be submitted to NERC on the schedule established by NERC, generally on or about October 1 of the preceding year. In conjunction with the annual Regional Implementation Plan, each Regional Entity must report to NERC regarding how it carried out its delegated compliance monitoring and enforcement authority in the previous year, the effectiveness of the Compliance Monitoring and Enforcement Program, and changes expected to correct any deficiencies identified. Each Regional Entity will provide its annual report on the schedule established by NERC, generally on or about February 15 of the following year.

404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users

NERC shall monitor Regional Entity compliance with NERC Reliability Standards and, if no there is no delegation agreement in effect with a Regional Entity for the geographic area, shall monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards. Industry subject matter experts may be used as appropriate in Compliance Investigations, Compliance Audits, and other Compliance Monitoring and Enforcement Program activities, subject to confidentiality, antitrust, and conflict of interest provisions.

1. **NERC Obligations** — NERC Compliance Staff shall monitor the compliance of the Regional Entity with the Reliability Standards for which the Regional Entities are responsible, in accordance with **Appendix 4C**. NERC shall actively monitor in its annual Compliance Enforcement and Monitoring Program selected Reliability Standards that apply to the Regional Entities. NERC shall evaluate compliance and noncompliance with all of the Reliability Standards that apply to the Regional Entities and shall impose sanctions, Penalties, or Remedial Action Directives when there is a finding of noncompliance. NERC shall post all violations of Reliability Standards that apply to the Regional Entities as described in the reporting and disclosure process in **Appendix 4C**.

   In addition, NERC will directly monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the Compliance Enforcement Authority described in **Appendix 4C**. Compliance matters contested by Bulk Power System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Compliance Audit of the Regional Entity** — NERC shall perform a Compliance Audit of each Regional Entity responsible for complying with Reliability Standards at least once every three years. NERC shall make an evaluation of compliance based on the information obtained through the Compliance Audit. After due process is complete, the final Compliance Audit report shall be made public in accordance with the reporting and disclosure process in **Appendix 4C**.

3. **Appeals Process** —Any Regional Entity or Bulk Power System owner, operator or user found by NERC, as opposed to a Regional Entity, to be in noncompliance

with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC

The NERC Compliance and Certification Committee shall establish and implement a process to monitor NERC's compliance with the Reliability Standards that apply to NERC. The process shall use independent monitors with no conflict of interest, real or perceived, in the outcomes of the process. All violations shall be made public according to the reporting and disclosure process in **Appendix 4C**. The Compliance and Certification Committee will also establish a procedure for monitoring NERC's compliance with its Rules of Procedure for the Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs. Such procedures shall not be used to circumvent the appeals processes established for those programs.

406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of its Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the NERC Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entity Compliance Monitoring and Enforcement Programs and the effectiveness of the programs in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with **Appendix 4C**.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the NERC Compliance Monitoring and Enforcement Program, the administrators of the NERC Compliance Monitoring and Enforcement Program shall provide a written response and plan to the Board within 30 days of the release of the final audit report.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions and Remedial Action Directives that are specified by a Regional Entity

Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination is supported by a sufficient record compiled by the Regional Entity, is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance and directions issued by NERC pursuant to the delegation agreement, and is consistent with Penalties, sanctions and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Compliance Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a "Notice of Penalty" and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity or a Regional Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity Compliance Monitoring and Enforcement Program audit finding, may do so by filing a notice of the challenge with NERC's director of enforcement no later than 21 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Regional Entity Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of challenge, the NERC director of enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — The NERC Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter

based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's director of enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, the NERC Compliance Monitoring and Enforcement Program staff may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Compliance Committee may invite representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program to appear before the Compliance Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Regional Entity Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the Compliance Enforcement Authority, or an owner, operator or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Regional Entity Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's

director of enforcement, with copies to the Regional Entity and any other Participants in the Regional Entity Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Regional Entity Hearing Body.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Regional Entity Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Regional Entity Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Regional Entity shall file the entire record of the Regional Entity Hearing Body proceeding with NERC's director of enforcement, with a copy to the Participant filing the notice. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Regional Entity Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The Registered Entity filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Regional Entity Hearing Body, the responses, and any reply filed with NERC. At its discretion, the Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Regional Entity Hearing Body to appear before the Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Regional Entity Hearing Body granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding. Appeals of decisions of Regional Entity Hearing Bodies granting or denying motions to intervene in Regional Entity Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to

include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement, and the request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standard*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Regional Entity Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Regional Entity Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees, for decision, a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Regional Entity Hearing Body to the Board of Trustees shall be considered and disposed of by the Compliance Committee.

2. The Compliance Committee may accept or reject a certification of a question for decision. If the Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Regional Entity Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Compliance Committee. The Compliance Committee may also request, or provide an opportunity for, the NERC compliance operations department, the NERC compliance enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda as are filed in accordance with the schedule, the Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Compliance Committee's written decision on the certified question, the Regional Entity Hearing Body shall proceed to complete the hearing in accordance with the Compliance Committee's decision.

5. The Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Regional Entity Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Regional Entity Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity Compliance Monitoring and Enforcement Program. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9 and 6.5 of Appendix 4C.

414. Appeals of Decisions of Regional Entity Hearing Bodies Granting or Denying Motions to Intervene in Regional Entity Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Regional Entity Hearing Body proceeding, and the Regional Entity Compliance Staff or any other Participant in the Regional Entity Hearing Body proceeding may appeal a decision of the Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding, in either case by filing a notice of appeal with the NERC director of enforcement, with copies to the Regional Entity Clerk, the Regional Entity Hearing body, the Hearing Officer, the Regional Entity Compliance Staff, and all other Participants in the Regional Entity Hearing Body proceeding, no later than seven (7) days following the date of the Regional Entity Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Regional Entity Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Regional Entity Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Regional Entity Clerk shall transmit to the NERC director of enforcement copies of all pleadings filed in the Regional Entity Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Regional Entity Hearing Body, the Regional Entity Compliance Staff, and any other Participants in the Regional Entity Hearing Body proceeding, may each file a response to the notice of appeal with the NERC director of enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Regional Entity Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC director of enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Compliance Committee. The NERC director of enforcement shall provide copies of the notice of appeal and any responses and replies to the Compliance Committee. The Compliance Committee shall issue a written decision on the appeal; provided, that if the Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Regional Entity Hearing Body granting or denying the motion to intervene shall stand. The NERC director of enforcement shall transmit copies of the Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Compliance Committee, to the Regional Entity Clerk, the Regional Entity Hearing Body, the entity filing the notice of appeal, the Regional Entity Compliance Staff, and any other Participants in the Regional Entity Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Compliance Committee on an appeal of a Regional Entity Hearing Body decision granting or denying a motion to intervene in a Regional Entity Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Compliance Committee to FERC or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Refer to Section 507.

(c) Multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. This includes those

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

entities that satisfy the criteria established in the NERC provisional Certification process. The NERC programs shall:

2.1 Evaluate and certify the competency of entities performing reliability functions. The entities presently expected to be certified include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Evaluate and certify each applicant's ability to meet the requirements for Certification.

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements, and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections V and VI, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.8.d.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

      2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification

Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with their members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

    2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

    3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

    3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

    3.3 Regional Entities shall notify NERC of all Certification applicants.

    3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

    3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

        3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to

support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be posted by NERC for public viewing.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every

recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. Any entity seeking to register as a JRO must submit a written agreement with its members or related entities for all Requirements/sub-Requirements for the function(s) for which the entity is registering for and takes responsibility for, which would otherwise be the responsibility of one or more of its members or related entities. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the JRO Registration.

2. The JRO Registration data must include the same Registration information as a normal compliance Registration entry. The JRO is responsible for providing all of the information and data, including submitting reports, as needed by the Regional Entity for performing assessments of compliance.

3. The Regional Entity shall notify NERC of each JRO that the Regional Entity accepts. The notification will identify the point of contact and the functions(s) being registered for on behalf of its members or related entities.

4. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs. This document shall contain a list of each JRO's members or related entities and the function(s) for which the JRO is registered for that member(s) or related entity(s). It is the responsibility of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

5. The Regional Entity may request clarification of any list submitted to it that identifies the members of the JRO and may request such additional information as the Regional Entity deems appropriate.

6. The Regional Entity's acceptance of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the JRO will meet the Registration requirements of Section 501(1.4).

7. NERC shall maintain, and post on its website, a JRO registry listing all JRO Registrations that have been reviewed and accepted by the Regional Entity. The posting shall identify the JRO entity taking compliance responsibilities for itself and its members.

8. The JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

9. Nothing in Section 507 shall preclude a member of a JRO, a related entity, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the member or other entity is registering. A JRO member or related entity that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the JRO of its Registration.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.

2. Each CFR or each individual entity within a CFR must identify a point of contact that is responsible for providing information and data, including submitting reports as needed by the Regional Entity related to the CFR Registration.

3. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts.

4. NERC or the Regional Entity may request clarification of any list submitted to it that identifies the compliance responsibilities of the CFR and may request such additional information as NERC or the Regional Entity deems appropriate.

5. The Regional Entity's acceptance of that CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the CFR will meet the Registration requirements of Section 501(1.4).

6. NERC shall maintain, and post on its website, a CFR registry listing all CFR Registrations that have been accepted by NERC or by a Regional Entity. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

7. The point of contact shall inform the Regional Entity of any changes to an existing CFR. The Regional Entity shall promptly notify NERC of each such revision.

8. In the event of a violation of a Reliability Standard or of a Requirement/sub-Requirement of a Reliability Standard for which an entity of a CFR is registered, that entity shall be identified in the Notice of Alleged Violation and shall be assessed the sanction or Penalty in accordance with the NERC Sanctions Guidelines. In the event a Regional Entity is not able to determine which entity(ies) is responsible for a particular Reliability Standard, or Requirements/sub-Requirements thereof that has been violated, the Regional Entity shall investigate the noncompliance in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*, to determine the entity(ies) to which the Regional Entity shall to issue the sanction or Penalty for the violation.

9. Nothing in Section 508 shall preclude an entity registered in a CFR, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the entity is registering. An entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the point of contact of its Registration.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION

601. Scope of Personnel Certification

Maintaining the reliability of the Bulk Electric System through implementation of the Reliability Standards requires skilled, trained and qualified system operators. The Personnel Certification Program provides the mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the Bulk Electric System. The Personnel Certification awards system operator Certification Credentials to individuals who demonstrate that they have attained essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations. NERC, as the ERO, will ensure skilled, trained, and qualified system operators through the Personnel Certification Program.

Except as necessary to obtain approval of the Rules of Procedure, the NERC Personnel Certification Governance Committee (PCGC) is the governing body that establishes the policies, sets fees, and monitors the performance of the Personnel Certification Program for system operators.

602. Structure of ERO Personnel Certification Program

1. The NERC Personnel Certification Program shall be international in scope.
2. The PCGC shall (1) be able to independently exercise decision-making for all matters pertaining to Certification, (2) include individuals from the discipline being certified and whose composition addresses the needs of the users of the program (e.g., employers, regulators, etc.), and (3) have representation for each specialty or level within a discipline.
3. NERC shall maintain a nominating process for membership in the governing body. Nominations shall be open to all interested parties and self-nominations shall be accepted. The NERC Board of Trustees shall appoint members to the governing body from among those nominated. The members of the governing body shall serve at the pleasure of the Board.
4. The PCGC shall have control over the matters related to the Personnel Certification and re-Certification Programs listed below, without being subject to approval by any other body.

    4.1 Policies and procedures, including eligibility requirements and application processing.

    4.2 Requirements for personnel Certification, maintaining Certification, and re-Certification.

    4.3 Examination content, development, and administration.

    4.4 Examination cut score.

4.5 Grievance and disciplinary processes.

4.6 Governing body and subgroup(s)' meeting rules including agenda, frequency, and related procedures.

4.7 Subgroup(s) appointments and work assignments.

4.8 Publications about personnel Certification and re-Certification.

4.9 Setting fees for application, and all other services provided as a part of the personnel Certification and re-Certification activities.

4.10 Program funding, spending, and budget authority. Financial matters related to the operation of the program shall be segregated from other NERC activities.

5. The Personnel Certification Program shall utilize written procedures for the selection of members of the governing body that prohibit the governing body from selecting a majority of its successors.

6. The Personnel Certification Program shall be separate from the accreditation and education functions of NERC in related disciplines.

7. No member of the PCGC or staff member working with the Personnel Certification Program governing body shall have or exercise any authority or responsibility for compliance matters related to Reliability Standards concerning personnel Certification.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will

investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

   5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

3.2. Probation: A letter will be sent from NERC to the offender specifying:

3.2.1. The length of time of the probationary period (to be determined by the PCGC).

3.2.2. Credential will remain valid during the probationary period.

3.2.3. The probationary period does not affect the expiration date of the current certificate.

3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

3.3.1. The length of time of the probationary period (to be determined by the PCGC).

3.3.2. Credential is no longer valid.

3.3.3. Successfully passing an exam will be required to become recertified.

3.3.4. An exam will not be authorized until the revocation period expires

3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing Mechanisms

1. The Personnel Certification Program shall utilize reliable testing mechanisms to evaluate individual competence in a manner that is objective, fair to all candidates, job-related, and based on the knowledge and skill needed to function in the discipline.

2. The Personnel Certification Program shall implement a formal policy of periodic review of the testing mechanisms to ensure ongoing relevance of the mechanisms to knowledge and skill needed in the discipline.

3. The Personnel Certification Program shall utilize policies and procedures to ensure that all test administration and development materials are secure and demonstrate that these policies and procedures are consistently implemented.

4. The Personnel Certification Program shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted in the psychometric community as being fair and reasonable.

5. The Personnel Certification Program shall conduct ongoing studies to substantiate the reliability and validity of the testing mechanisms.

6. The Personnel Certification Program shall utilize policies and procedures that govern how long examination records are kept in their original format.

7. The Personnel Certification Program shall demonstrate that different forms of the testing mechanisms assess equivalent content and that candidates are not penalized for taking forms of varying difficulty.

607. Public Information About the Personnel Certification Program

1. The Personnel Certification Program shall maintain and publish publicly a System Operator Certification Program Manual describing the procedures used in examination construction and validation; all eligibility requirements and determination; fees; and examination administration documents, including: reporting of results, re-Certification requirements, and disciplinary and dispute resolution.

2. The Personnel Certification Program shall maintain and publish publicly a comprehensive summary or outline of the information, knowledge, or functions covered by each examination.

3. The Personnel Certification Program shall publish publicly and make available at least annually a summary of Certification activities for the program, including at least the following information: number of examinations delivered, the number passed, the number failed, and the number certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The Personnel Certification Program:

1. Shall not discriminate among applicants as to age, gender, race, religion, national origin, disability, or marital status and shall include a statement of non-discrimination in announcements of the program.

2. Shall comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services.

3. Shall make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants.

4. Shall implement a formal policy for the periodic review of eligibility criteria and application procedures to ensure that they are fair and equitable.

5. Shall provide competently proctored examination sites.

6. Shall uniformly report examination results to applicants in a timely manner.

7. Shall give applicants failing the examination information on general content areas of deficiency.

609. Responsibilities to the Public and to Employers of Certified Practitioners

The Personnel Certification Program:

1. Shall demonstrate that the testing mechanisms adequately measure the knowledge and skill required for entry, maintenance, and/or advancement in the profession for each position to be certified.

2. Shall award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable.

3. Shall maintain, in an electronic format, a current list of those persons certified in the programs and have policies and procedures that delineate what information about a Credential holder may be made public and under what circumstances.

4. Shall have formal policies and procedures for discipline of a Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

5. Shall demonstrate that any title or Credential awarded accurately reflects or applies to the practitioner's daily occupational or professional duties and is not confusing to employers, consumers, regulators, related professions, and/or other interested parties.

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

   1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

   1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

   1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

   1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

   1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems, operational readiness of the affected Regional Entities for the upcoming season

shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Maintaining the reliability of the Bulk Electric System through implementation of the Reliability Standards requires informed and trained personnel. The training and education program will provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the Bulk Electric System.

NERC shall develop and maintain training and education programs for the purpose of establishing training requirements, developing materials, and developing training activities. The target audience of the training and education programs shall be Bulk Power System operating personnel including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, training personnel, and other personnel directly responsible for complying with NERC Reliability Standards who, through their actions or inactions, may impact the real-time, or day-ahead reliability of the Bulk Power System.

NERC shall also develop and provide appropriate training and education for industry participants and regulators affected by new or changed Reliability Standards or compliance Requirements.

To accomplish those objectives:

1. NERC shall periodically conduct job task analyses for targeted Bulk Power System personnel to ensure that the training program content is properly aligned to the job tasks performed by those personnel.

2. NERC shall develop and maintain personnel training program curriculum requirements based on valid job-task analysis.

3. NERC shall periodically conduct performance surveys to determine the effectiveness of the training program and identify areas for further training development and improvement.

4. NERC shall develop training and education materials and activities to assist Bulk Power System entities implementing new or revised Reliability Standard Requirements or other NERC-related changes.

5. NERC shall develop and provide training to people who participate in NERC and Regional Entity evaluations, audits, and investigations for the Compliance Monitoring and Enforcement Program, Organization Certification Program, and the continuing education program.

902. Continuing Education Program

NERC shall develop and maintain a continuing education program to foster the improvement of training and to promote quality in the training programs used by and

implemented by Bulk Power System entities. The program shall approve or accredit those activities and entities meeting NERC continuing education requirements.

1. NERC shall develop and implement continuing education program requirements that promote excellence in training programs and advance improved performance for Bulk Power System personnel identified in Section 901.

2. NERC shall develop and maintain a process to approve or accredit continuing education Providers and activities seeking approval or accreditation and meeting NERC-approved continuing education requirements.

3. NERC shall perform periodic audits on continuing education Providers and training activities to ensure that the approved or accredited Providers and training activities satisfy NERC continuing education requirements.

4. NERC shall develop and maintain an appeals process for disputed application reviews, interpretations of guidelines and standards, probation or suspension of NERC-approved Provider status, or Continuing Education Hour disputes.

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electric Sector Information Sharing and Analysis Center (ESISAC)

    1.1 NERC shall serve as the electricity sector's sector coordinator and operate its Information Sharing and Analysis Center to gather information and communicate security-related threats and incidents within the sector, with United States and Canadian government agencies, and with other Critical Infrastructure sectors.

    1.2 NERC shall improve the capability of the ESISAC to analyze security threats and incident information and provide situational assessments for the electricity sector and governments.

    1.3 NERC shall work closely with the United States Department of Homeland Security, Department of Energy, Natural Resources Canada, and Public Safety and Emergency Preparedness Canada.

    1.4 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.5 NERC shall fill the role of the Electricity Sector Coordinating Council and coordinate with the Government Coordinating Council.

    1.6 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, the other ISACs, and the National Infrastructure Advisory Committee.

    1.7 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, and recognizing that mitigation and recovery can be practical alternatives to prevention.

2.2 NERC shall keep abreast of the changing threat environment through collaboration with government agencies.

2.3 NERC shall develop criteria to identify critical physical assets and Critical Cyber Assets, assess security threats, identify risk assessment methodologies, and assess effectiveness of physical and cyber protection measures.

2.4 NERC shall enhance and maintain the Bulk Power System critical spare transformer program, encourage increased participation by asset owners, and continue to assess the need to expand this program to include other critical Bulk Power System equipment.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness and respond to the needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters; work with DOE and DHS to implement the National Infrastructure Protection Plan, as applicable to the electricity sector; and coordinate this work with PSEPC.

2.10 NERC shall improve methods to better assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

2.11 NERC shall assess the results of vulnerability assessments and enhance the security of system control and data acquisition (SCADA) and process control systems by developing methods to detect an emerging cyber attack and the means to mitigate impacts on the Bulk Power Systems.

2.12 NERC shall work with the National SCADA Test Bed and the Process Control Systems Forum to accelerate the development of technology that

will enhance the security, safety, and reliability of process control and SCADA systems.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources

provided for in the budget to carry out the ERO program responsibilities; explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding requirement (including Regional Entity costs for delegated functions), and (3) the

mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[3] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional Entity will collect directly from the Load-Serving Entities or as otherwise

[3] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may

request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional

information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted

on NERC's website at approximately the same time that notice is given to committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

4. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

5. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the "Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or

any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement in a form approved by NERC's Board of Trustees.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief

executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Confirmed Violations** — Nothing in this Section 1500 shall prohibit the disclosure of a violation at the point when the matter is filed with an Applicable Governmental Authority as a Notice of Penalty, the "violator" admits to the violation, or the alleged violator and NERC or the Regional Entity reach a settlement regarding the violation.

2. **Compliance Information** — NERC and the Regional Entities are authorized to exchange Confidential Information related to evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses information determined to be confidential may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500

precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating" or "identity masking"); and (vi) an estimate of the relative burden

imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

   2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

   2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

   2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: TBD

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SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted. Such functional classes[1] include: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, market operators, Planning Authorities, Transmission Planners, Resource Planners, Load-Serving Entities, and Distribution Providers. Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance**— Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance**— The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** —Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome**— Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations**— Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments or revisions to the *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

   3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

   3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment or apply to change Segments at any time.

   3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments at least every three years to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to

belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC shall assign a standards process manager to administer the development of continent-wide Reliability Standards and a regional standards manager to administer the development of Regional Reliability Standards. The standards process manager shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual*. The standards process manager and the regional standards manager shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. The regional standards manager shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC or directs NERC to develop a Reliability Standard, NERC shall within five (5) business days notify all other Applicable Governmental Authorities, and shall within thirty (30) calendar days report to all Applicable Governmental Authorities

a plan and timetable for modification or development of the Reliability Standard. Reliability Standards that are remanded or directed by an Applicable Governmental Authority shall be modified or developed using the *Standard Processes Manual*. NERC shall, during the development of a modification for the remanded Reliability Standard or directed Reliability Standard, consult with other Applicable Governmental Authorities to coordinate any impacts of the proposed Reliability Standards in those other jurisdictions. The expedited standards development process may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authorities, respecting to the extent possible the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the expedited action process described in the *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

   3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

      3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

      3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material

interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard, due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

    3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

    3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability

Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory

within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or regional Variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — NERC shall maintain a current catalog of Regional Criteria. Regional Entities shall provide a catalog listing of Regional Criteria to NERC and shall notify NERC of changes to the listing. Regional Entities shall provide any listed document to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the

governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Accreditation

NERC shall seek and maintain accreditation of the NERC Reliability Standards development process by the American National Standards Institute.

317. Five-Year Review of Reliability Standards

NERC shall complete a review of each NERC Reliability Standard at least once every five years, or such longer period as is permitted by the American National Standards Institute, from the effective date of the Reliability Standard or the latest revision to the Reliability Standard, whichever is later. The review process shall be conducted in accordance with the NERC *Standard Processes Manual*. The standards process manager shall be responsible for administration of the five-year review of Reliability Standards. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely

as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC standards information manager of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the *Standard Processes Manual*, **Appendix 3A** to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities. If the Board of Trustees is presented with a proposed Reliability Standard that fails to address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a

timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; and (iii) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

   2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

   2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

   4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in

the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

5.5 A Reliability Standard approved under paragraph 5 of this Rule shall not be eligible for submission as an American National Standard.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

SECTION 400 — COMPLIANCE ENFORCEMENT

401. Scope of the NERC Compliance Monitoring and Enforcement Program

1. **Components of the NERC Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a NERC Compliance Monitoring and Enforcement Program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC that has been approved by the Applicable Governmental Authority) has been given enforcement authority. There are four distinct parts of the NERC Compliance Monitoring and Enforcement Program: (1) NERC's oversight of the Regional Entity Compliance Monitoring and Enforcement Programs (Section 402), (2) the definition of the required Regional Entity Compliance Monitoring and Enforcement Program attributes (Section 403), (3) NERC's monitoring of Regional Entity compliance with Reliability Standards (Section 404), and (4) the monitoring of compliance with Reliability Standards that are applicable to NERC (Sections 405–406).

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users, Regional Entities, and NERC, are required to comply with all approved NERC Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered NERC Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards and compliance reporting procedures.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer a Regional Entity Compliance Monitoring and Enforcement program to meet the NERC Compliance Monitoring and Enforcement Program goals and the requirements in this Section 400.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity in the event that NERC does not have a delegation agreement, or the Regional Entity withdraws from the agreement or does not operate its Compliance Monitoring and Enforcement Program in accordance with the delegation agreement or other applicable requirements.

5.1 Should NERC not have a delegation agreement with a Regional Entity covering a geographic area, or a Regional Entity withdraws from an existing delegation agreement or the delegation agreement is otherwise terminated, NERC will directly administer the Compliance Monitoring and Enforcement Program applicable to owners, operators and users of the Bulk Power System within that geographic area.

1. This monitoring and enforcement will be accomplished by NERC and Compliance Staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant compliance information regarding Registered Entities, contacts, prior compliance information and actions, Mitigation Plans, and Remedial Action Directives for the period in which the Regional Entity was responsible for administering the Compliance Monitoring and Enforcement Program.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies collected to offset the expenses of administering the Compliance Monitoring and Enforcement Program for the geographic area.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the Compliance Monitoring and Enforcement Program within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. ~~**Actively Monitored Requirements**~~**Risk Elements** — NERC, with input from the Regional entities, stakeholders, and regulators, shall at least annually ~~select a subset of the~~identify risk elements to prioritize risks to the reliability of the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements are to be ~~actively monitored and audited~~considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan. NERC identifies the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. NERC uses these risk elements to identify and prioritize interconnection and continent-wide risks to the reliability of the Bulk Power System. These identified risks, as well as risks to the reliability of the Bulk Power System identified by Regional Entities for their footprint, represent the focus for monitoring activities in the upcoming year, and become inputs for developing oversight plans for individual Registered Entities. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable NERC Reliability Standards whether or not they

are ~~included in the subset of Reliability Standards and Requirements designated~~identified as areas of focus to be ~~actively monitored and~~considered for compliance oversight ~~audited~~ in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which is incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC shall maintain a record of each compliance submission, including Self-Reported, Possible, Alleged, and Confirmed Violations of approved Reliability Standards; associated Penalties, sanctions, Remedial Action Directives and settlements; and the status of mitigation actions.

10. **Confidential Information** — NERC will treat all Possible and Alleged Violations of Reliability Standards and matters related to a Compliance Monitoring and Enforcement Program process, including the status of any Compliance Investigation or other Compliance Monitoring and Enforcement Program process, as confidential in accordance with Section 1500.

    The types of information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500. Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident, will be identified and protected from public disclosure as Critical Energy Infrastructure Information in accordance with Section 1500.

    The Regional Entity and NERC shall give Bulk Power System owners, operators, and users a reasonable opportunity to demonstrate that information concerning a violation is confidential before such report is disclosed to the public.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with a Possible or Alleged Violation(s) of a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a Possible or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC shall, subject to the confidentiality requirements of these Rules of Procedure, publicly post each Confirmed Violation, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation report, on its website.

11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the Confirmed Violation or report to be posted publicly. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

11.2 In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information (*NERC Security Guidelines for the Electricity Sector — Protecting Potentially Sensitive Information* may be used as a guide) or other Confidential Information shall be redacted in accordance with Section 1500 and not be released publicly.

11.3 Subject to redaction of Critical Energy Infrastructure Information or other Confidential Information, for each Confirmed Violation or settlement relating to a Possible Violation or an Alleged Violation, the public posting shall include the name of any relevant entity, the nature, time period, and circumstances of such Possible, Alleged or Confirmed Violation, any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity in connection with the Confirmed Violation or settlement, and sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Violation Information Review** — NERC Compliance Staff shall periodically review and analyze all reports of Possible, Alleged and Confirmed Violations to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs

1. **NERC Monitoring Program** — NERC shall have a program to monitor the Compliance Monitoring and Enforcement Program of each Regional Entity that has been delegated authority. The objective of this monitoring program shall be to ensure that the Regional Entity carries out its Compliance Monitoring and Enforcement Program in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's Compliance Monitoring and Enforcement Program. Oversight and monitoring by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, and regular evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance as described below.

1.1 **NERC Review of Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans** — NERC shall require each Regional Entity to submit for review and approval an annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan. NERC shall review each annual Regional Entity

Compliance Monitoring and Enforcement Program Implementation Plan and shall accept the plan if it meets NERC requirements and the requirements of the delegation agreement.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity Compliance Monitoring and Enforcement Program implements the NERC Compliance Monitoring and Enforcement Program. The evaluation shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreement, directives in effect pursuant to the delegation agreement, approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans, required Compliance Monitoring and Enforcement Program attributes, and the NERC Compliance Monitoring and Enforcement Program procedures. These evaluations shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 3.1.6 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity Compliance Monitoring and Enforcement Program. The current procedure is contained in the NERC Audit of Regional Entity Compliance Programs, which is incorporated into these rules as **Appendix 4A**.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's

Compliance Monitoring and Enforcement Program. A representative of the Regional Entity being audited will be allowed to participate in the audit as an observer.

2. **Consistency Among Regional Compliance Monitoring and Enforcement Programs** — To provide for a consistent Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program, which is incorporated into these rules of procedure as **Appendix 4C**. Any differences in Regional Entity Compliance Monitoring and Enforcement Program methods, including determination of violations and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

   2.1 NERC shall ensure that each of the Regional Entity Compliance Monitoring and Enforcement Programs meets these Rules of Procedure, including **Appendix 4C**, and follows the terms of the delegation agreement and the approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan.

   2.2 NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program in **Appendix 4C** containing the procedures to ensure the consistency and fairness of the processes used to determine Regional Entity Compliance Monitoring and Enforcement Program findings of compliance and noncompliance, and the application of Penalties and sanctions.

   2.3 NERC shall periodically conduct Regional Entity compliance manager forums. These forums shall use the results of Regional Entity Compliance Monitoring and Enforcement Program audits and findings of NERC Compliance Staff to identify and refine Regional Entity Compliance Monitoring and Enforcement Program differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Violation Disclosure** — NERC shall disclose all Confirmed Violations and maintain as confidential Possible Violations and Alleged Violations, according to the reporting and disclosure process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — NERC and Regional Entity Compliance Staff shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties

and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Regional Entity boards or a compliance panel reporting directly to the Regional Entity board will be vested with the authority for the overall Regional Entity Compliance Monitoring and Enforcement Program and have the authority to impose Penalties and sanctions on behalf of NERC, where authorized by applicable legislation or agreement. Remedial Action Directives may be issued by NERC or a Regional Entity that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert a violation of a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections 408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

   The appeals process will also allow for appeals to NERC of any findings of noncompliance issued by NERC to a Regional Entity for Reliability Standards and Requirements where the Regional Entity is monitored for compliance to a Reliability Standard. No monetary Penalties will be levied in these matters; however sanctions, remedial actions, and directives to comply may be applied by NERC.

7. **Conflict Disclosure** — NERC shall disclose to the appropriate governmental authorities any potential conflicts between a market rule and the enforcement of a Regional Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the NERC Compliance Monitoring and Enforcement Program, NERC and Regional Entity staff, Compliance Audit team members, and committee members shall maintain the confidentiality of information obtained and shared during compliance monitoring and enforcement processes including Compliance Investigations, Compliance Audits, Spot Checks, drafting of reports, appeals, and closed meetings.

   8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for staff and other Compliance Monitoring and Enforcement Program participants.

8.2 Individuals not bound by NERC or Regional Entity codes of conduct who serve on compliance-related committees or Compliance Audit teams shall sign a NERC confidentiality agreement prior to participating on the committee or Compliance Audit team.

8.3 Information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall not be distributed outside of a committee or team, nor released publicly. Other information subject to confidentiality is identified in Section 1500.

8.4 In the event that a staff, committee, or Compliance Audit team member violates any of the confidentiality rules set forth above, the staff, committee, or Compliance Audit team member and any member organization with which the individual is associated may be subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future Compliance Monitoring and Enforcement Program activities.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to all people who participate in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs

Each Regional Entity Compliance Monitoring and Enforcement Program shall promote excellence in the enforcement of Reliability Standards. To accomplish this goal, each Regional Entity Compliance Monitoring and Enforcement Program shall (i) conform to and comply with the NERC uniform Compliance Monitoring and Enforcement Program, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its Compliance Monitoring and Enforcement Program shall exhibit independence, meaning the Compliance Monitoring and Enforcement Program shall be organized so that its compliance monitoring and enforcement activities are carried out separately from other activities of the Regional Entity. The Compliance Monitoring and Enforcement Program shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored or other Regional Entity activities that are required to meet the Reliability Standards. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity Compliance Monitoring and Enforcement Program shall exercise the responsibility and authority in carrying out the delegated functions of the NERC Compliance Monitoring and Enforcement Program in accordance with delegation agreements and **Appendix 4C**. These functions include but are not limited to: data gathering, data reporting, Compliance Investigations, Compliance Audit activities, evaluating compliance and noncompliance, imposing Penalties and sanctions, and approving and tracking mitigation actions.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the NERC Compliance Monitoring and Enforcement Program, a Regional Entity shall not sub-delegate its Compliance Monitoring and Enforcement Program duties to entities or persons other than the Regional Entity Compliance Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** The Regional Entity board or compliance panel reporting directly to the Regional Entity board (with appropriate recusal procedures) will be vested with the authority for conducting compliance hearings in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single segment may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Compliance Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the Regional Entity Compliance Monitoring and Enforcement Program.

6. **Regional Entity Compliance Staff Independence** — The Regional Entity Compliance Staff shall be capable of and required to make all determinations of compliance and noncompliance and determine Penalties, sanctions, and Remedial Action Directives and to review and accept Mitigation Plans and other Mitigating Activities.

    6.1 Regional Entity Compliance Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

    6.2 Regional Entity Compliance Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement

processes (with the input of industry subject matter experts), make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

6.3 Regional Entity Compliance Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

6.4 Regional Entity Compliance Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure, the NERC delegation agreement and other confidentiality agreements required by the NERC Compliance Monitoring and Enforcement Program.

6.5 Contracting with independent consultants or others working for the Regional Entity Compliance Monitoring and Enforcement Program shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals for the purpose of these Rules of Procedure shall be considered as augmenting Regional Entity Compliance Staff.

7. Use of Industry Subject Matter Experts and Regional Entity Members — Industry experts and Regional Entity members may be called upon to provide their technical expertise in Compliance Monitoring and Enforcement Program activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity Compliance Staff so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than the Compliance Staff of the Regional Entity. Industry subject matter experts, Regional Entity members, or

Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Regional Entity Compliance Monitoring and Enforcement Program Content** — All approved Reliability Standards shall be included in the Regional Entity Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users within the defined boundaries of the Regional Entity. Compliance to approved Regional Reliability Standards is applicable only within the Region of the Regional Entity that submitted those particular Regional Reliability Standards for approval. NERC will identify the risk elements and related ~~minimum set of~~ Reliability Standards and Requirements to be ~~actively monitored~~considered by the Regional Entity in a given year in developing oversight plans for individual Registered Entities.

9. **Antitrust Provisions** — Each Regional Entity's Compliance Monitoring and Enforcement Program shall be structured and administered to abide by U.S. antitrust law and Canadian competition law.

10. **Information Submittal** — All Bulk Power System owners, operators, and users within the Regional Entity responsible for complying with Reliability Standards shall submit timely and accurate information when requested by the Regional Entity or NERC. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

10.1 Each Regional Entity has the authority to collect the necessary information to determine compliance and shall develop processes for gathering data from the Bulk Power System owners, operators, and users the Regional Entity monitors.

10.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.10 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

10.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

10.4 Regional Entities shall notify NERC of all Possible, Alleged and Confirmed Violations of NERC Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

10.5 A Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan with a timeline addressing how the noncompliance will be corrected, unless an enforcement process is used that does not require a Mitigation Plan. The Regional Entity Compliance Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

10.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all compliance data Self-Reported to the Regional Entity Compliance Monitoring and Enforcement Program.

10.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

11. **Compliance Audits of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program of proactive Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**. A Compliance Audit is a process in which a detailed review of the activities of a Bulk Power System owner, operator, or user is performed to determine if that Bulk Power System owner, operator, or user is complying with approved Reliability Standards.

11.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, Compliance Audits shall be performed on a schedule established by NERC.

11.2 Compliance Audits of Balancing Authorities, Reliability Coordinators, and Transmission Operators will include a component at the audited entity's site. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, the Compliance Audit may be either an on-site Compliance Audit or based on review of documents, as determined to be necessary and appropriate by NERC or Regional Entity Compliance Staff.

11.3 Compliance Audits must include a detailed review of the activities of the Bulk Power System owner, operator, or user to determine if the Bulk Power System owner, operator, or user is complying with all approved Reliability Standards identified for audit by NERC. The Compliance Audit shall include a review of supporting documentation and evidence used by the Bulk Power System owner, operator or user to demonstrate compliance for an appropriate period prior to the Compliance Audit.

12. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and information obtained from such processes, are to be non-public and treated as confidential in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis, provided, that NERC and the Regional Entities shall publish (i) schedules of Compliance Audits scheduled in each year, (ii) a public report of each Compliance Audit, and (iii) Notices of Penalty and settlement agreements. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as specific allegations or conclusions regarding Possible or Alleged Violations of Reliability Standards are not included in such disclosures.

13. **Critical Energy Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will be identified and protected from public disclosure as Critical Energy Infrastructure Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

14. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing

with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

15. **Regional Entity Hearing Process** — Each Regional Entity Compliance Monitoring and Enforcement Program shall establish and maintain a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The Regional Entity hearing process shall be conducted before the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. The Regional Entity hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single segment may veto any matter brought before the Hearing Body after recusals.

    Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

    If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity hearing process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

16. **Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan** — Each Regional Entity shall annually develop and submit to NERC for approval a Regional Entity Compliance Monitoring and Enforcement Implementation Plan in accordance with **Appendix 4C** that, includes details on r~~R~~egional r~~R~~isk a~~A~~ssessment processes and results, Reliability Standards and Requirements associated with r~~R~~egional ~~R~~risk a~~A~~ssessment results, the methods to be used by the Regional Entity for reporting, monitoring, evaluati~~on~~ng, and assess~~ment of~~ ing performance criteria~~,~~ and the Regional Entity's Annual Audit Plan.~~identifies the Reliability Standards and Requirements to be actively monitored (both those required by NERC and any additional Reliability Standards the Regional Entity proposes to monitor), and how each NERC and Regional Entity identified Reliability Standard will be monitored,~~

~~evaluated, reported, sanctioned, and appealed.~~ These Regional Implementation Plans will be submitted to NERC on the schedule established by NERC, generally on or about October 1 of the preceding year. In conjunction with the annual Regional Implementation Plan, each Regional Entity must report to NERC regarding how it carried out its delegated compliance monitoring and enforcement authority in the previous year, the effectiveness of the Compliance Monitoring and Enforcement Program, and changes expected to correct any deficiencies identified. Each Regional Entity will provide its annual report on the schedule established by NERC, generally on or about February 15 of the following year.

404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users

NERC shall monitor Regional Entity compliance with NERC Reliability Standards and, if no there is no delegation agreement in effect with a Regional Entity for the geographic area, shall monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards. Industry subject matter experts may be used as appropriate in Compliance Investigations, Compliance Audits, and other Compliance Monitoring and Enforcement Program activities, subject to confidentiality, antitrust, and conflict of interest provisions.

1. **NERC Obligations** — NERC Compliance Staff shall monitor the compliance of the Regional Entity with the Reliability Standards for which the Regional Entities are responsible, in accordance with **Appendix 4C**. NERC shall actively monitor in its annual Compliance Enforcement and Monitoring Program selected Reliability Standards that apply to the Regional Entities. NERC shall evaluate compliance and noncompliance with all of the Reliability Standards that apply to the Regional Entities and shall impose sanctions, Penalties, or Remedial Action Directives when there is a finding of noncompliance. NERC shall post all violations of Reliability Standards that apply to the Regional Entities as described in the reporting and disclosure process in **Appendix 4C**.

   In addition, NERC will directly monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the Compliance Enforcement Authority described in **Appendix 4C**. Compliance matters contested by Bulk Power System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Compliance Audit of the Regional Entity** — NERC shall perform a Compliance Audit of each Regional Entity responsible for complying with Reliability Standards at least once every three years. NERC shall make an evaluation of compliance based on the information obtained through the Compliance Audit. After due process is complete, the final Compliance Audit report shall be made public in accordance with the reporting and disclosure process in **Appendix 4C**.

3. **Appeals Process** —Any Regional Entity or Bulk Power System owner, operator or user found by NERC, as opposed to a Regional Entity, to be in noncompliance

with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC

The NERC Compliance and Certification Committee shall establish and implement a process to monitor NERC's compliance with the Reliability Standards that apply to NERC. The process shall use independent monitors with no conflict of interest, real or perceived, in the outcomes of the process. All violations shall be made public according to the reporting and disclosure process in **Appendix 4C**. The Compliance and Certification Committee will also establish a procedure for monitoring NERC's compliance with its Rules of Procedure for the Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs. Such procedures shall not be used to circumvent the appeals processes established for those programs.

406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of its Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the NERC Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entity Compliance Monitoring and Enforcement Programs and the effectiveness of the programs in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with **Appendix 4C**.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the NERC Compliance Monitoring and Enforcement Program, the administrators of the NERC Compliance Monitoring and Enforcement Program shall provide a written response and plan to the Board within 30 days of the release of the final audit report.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions and Remedial Action Directives that are specified by a Regional Entity

Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination is supported by a sufficient record compiled by the Regional Entity, is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance and directions issued by NERC pursuant to the delegation agreement, and is consistent with Penalties, sanctions and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Compliance Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a "Notice of Penalty" and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity or a Regional Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity Compliance Monitoring and Enforcement Program audit finding, may do so by filing a notice of the challenge with NERC's director of enforcement no later than 21 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Regional Entity Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of challenge, the NERC director of enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — The NERC Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter

based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's director of enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, the NERC Compliance Monitoring and Enforcement Program staff may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Compliance Committee may invite representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program to appear before the Compliance Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Regional Entity Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the Compliance Enforcement Authority, or an owner, operator or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Regional Entity Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's

director of enforcement, with copies to the Regional Entity and any other Participants in the Regional Entity Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Regional Entity Hearing Body.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Regional Entity Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Regional Entity Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Regional Entity shall file the entire record of the Regional Entity Hearing Body proceeding with NERC's director of enforcement, with a copy to the Participant filing the notice. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Regional Entity Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The Registered Entity filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Regional Entity Hearing Body, the responses, and any reply filed with NERC. At its discretion, the Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Regional Entity Hearing Body to appear before the Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Regional Entity Hearing Body granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding. Appeals of decisions of Regional Entity Hearing Bodies granting or denying motions to intervene in Regional Entity Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to

include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement, and the request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standard*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Regional Entity Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Regional Entity Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees, for decision, a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Regional Entity Hearing Body to the Board of Trustees shall be considered and disposed of by the Compliance Committee.

2. The Compliance Committee may accept or reject a certification of a question for decision. If the Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Regional Entity Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Compliance Committee. The Compliance Committee may also request, or provide an opportunity for, the NERC compliance operations department, the NERC compliance enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda as are

filed in accordance with the schedule, the Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Compliance Committee's written decision on the certified question, the Regional Entity Hearing Body shall proceed to complete the hearing in accordance with the Compliance Committee's decision.

5. The Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Regional Entity Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Regional Entity Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity Compliance Monitoring and Enforcement Program. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9 and 6.5 of Appendix 4C.

414. Appeals of Decisions of Regional Entity Hearing Bodies Granting or Denying Motions to Intervene in Regional Entity Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Regional Entity Hearing Body proceeding, and the Regional Entity Compliance Staff or any other Participant in the Regional Entity Hearing Body proceeding may appeal a decision of the Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding, in either case by filing a notice of appeal with the NERC director of enforcement, with copies to the Regional Entity Clerk, the Regional Entity Hearing body, the Hearing Officer, the Regional Entity Compliance Staff, and all other Participants in the Regional Entity Hearing Body proceeding, no later than seven (7) days following the date of the Regional Entity Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Regional Entity Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of

appeal shall include a copy of the original motion to intervene and a copy of the decision of the Regional Entity Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Regional Entity Clerk shall transmit to the NERC director of enforcement copies of all pleadings filed in the Regional Entity Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Regional Entity Hearing Body, the Regional Entity Compliance Staff, and any other Participants in the Regional Entity Hearing Body proceeding, may each file a response to the notice of appeal with the NERC director of enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Regional Entity Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC director of enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Compliance Committee. The NERC director of enforcement shall provide copies of the notice of appeal and any responses and replies to the Compliance Committee. The Compliance Committee shall issue a written decision on the appeal; provided, that if the Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Regional Entity Hearing Body granting or denying the motion to intervene shall stand. The NERC director of enforcement shall transmit copies of the Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Compliance Committee, to the Regional Entity Clerk, the Regional Entity Hearing Body, the entity filing the notice of appeal, the Regional Entity Compliance Staff, and any other Participants in the Regional Entity Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Compliance Committee on an appeal of a Regional Entity Hearing Body decision granting or denying a motion to intervene in a Regional Entity Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Compliance Committee to FERC or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Refer to Section 507.

(c) Multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. This includes those

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

entities that satisfy the criteria established in the NERC provisional Certification process. The NERC programs shall:

2.1 Evaluate and certify the competency of entities performing reliability functions. The entities presently expected to be certified include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Evaluate and certify each applicant's ability to meet the requirements for Certification.

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements, and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual,* Sections V and VI, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.8.d.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

      2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification

Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with their members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

    2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

    3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

    3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

    3.3 Regional Entities shall notify NERC of all Certification applicants.

    3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

    3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

        3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to

support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be posted by NERC for public viewing.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every

recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. Any entity seeking to register as a JRO must submit a written agreement with its members or related entities for all Requirements/sub-Requirements for the function(s) for which the entity is registering for and takes responsibility for, which would otherwise be the responsibility of one or more of its members or related entities. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the JRO Registration.

2. The JRO Registration data must include the same Registration information as a normal compliance Registration entry. The JRO is responsible for providing all of the information and data, including submitting reports, as needed by the Regional Entity for performing assessments of compliance.

3. The Regional Entity shall notify NERC of each JRO that the Regional Entity accepts. The notification will identify the point of contact and the functions(s) being registered for on behalf of its members or related entities.

4. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs. This document shall contain a list of each JRO's members or related entities and the function(s) for which the JRO is registered for that member(s) or related entity(s). It is the responsibility of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

5. The Regional Entity may request clarification of any list submitted to it that identifies the members of the JRO and may request such additional information as the Regional Entity deems appropriate.

6. The Regional Entity's acceptance of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the JRO will meet the Registration requirements of Section 501(1.4).

7. NERC shall maintain, and post on its website, a JRO registry listing all JRO Registrations that have been reviewed and accepted by the Regional Entity. The posting shall identify the JRO entity taking compliance responsibilities for itself and its members.

8. The JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

9. Nothing in Section 507 shall preclude a member of a JRO, a related entity, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the member or other entity is registering. A JRO member or related entity that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the JRO of its Registration.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.

2. Each CFR or each individual entity within a CFR must identify a point of contact that is responsible for providing information and data, including submitting reports as needed by the Regional Entity related to the CFR Registration.

3. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts.

4. NERC or the Regional Entity may request clarification of any list submitted to it that identifies the compliance responsibilities of the CFR and may request such additional information as NERC or the Regional Entity deems appropriate.

5. The Regional Entity's acceptance of that CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the CFR will meet the Registration requirements of Section 501(1.4).

6. NERC shall maintain, and post on its website, a CFR registry listing all CFR Registrations that have been accepted by NERC or by a Regional Entity. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

7. The point of contact shall inform the Regional Entity of any changes to an existing CFR. The Regional Entity shall promptly notify NERC of each such revision.

8. In the event of a violation of a Reliability Standard or of a Requirement/sub-Requirement of a Reliability Standard for which an entity of a CFR is registered, that entity shall be identified in the Notice of Alleged Violation and shall be assessed the sanction or Penalty in accordance with the NERC Sanctions Guidelines. In the event a Regional Entity is not able to determine which entity(ies) is responsible for a particular Reliability Standard, or Requirements/sub-Requirements thereof that has been violated, the Regional Entity shall investigate the noncompliance in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*, to determine the entity(ies) to which the Regional Entity shall to issue the sanction or Penalty for the violation.

9. Nothing in Section 508 shall preclude an entity registered in a CFR, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the entity is registering. An entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the point of contact of its Registration.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION

601. Scope of Personnel Certification

Maintaining the reliability of the Bulk Electric System through implementation of the Reliability Standards requires skilled, trained and qualified system operators. The Personnel Certification Program provides the mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the Bulk Electric System. The Personnel Certification awards system operator Certification Credentials to individuals who demonstrate that they have attained essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations. NERC, as the ERO, will ensure skilled, trained, and qualified system operators through the Personnel Certification Program.

Except as necessary to obtain approval of the Rules of Procedure, the NERC Personnel Certification Governance Committee (PCGC) is the governing body that establishes the policies, sets fees, and monitors the performance of the Personnel Certification Program for system operators.

602. Structure of ERO Personnel Certification Program

1. The NERC Personnel Certification Program shall be international in scope.
2. The PCGC shall (1) be able to independently exercise decision-making for all matters pertaining to Certification, (2) include individuals from the discipline being certified and whose composition addresses the needs of the users of the program (e.g., employers, regulators, etc.), and (3) have representation for each specialty or level within a discipline.
3. NERC shall maintain a nominating process for membership in the governing body. Nominations shall be open to all interested parties and self-nominations shall be accepted. The NERC Board of Trustees shall appoint members to the governing body from among those nominated. The members of the governing body shall serve at the pleasure of the Board.
4. The PCGC shall have control over the matters related to the Personnel Certification and re-Certification Programs listed below, without being subject to approval by any other body.

    4.1 Policies and procedures, including eligibility requirements and application processing.

    4.2 Requirements for personnel Certification, maintaining Certification, and re-Certification.

    4.3 Examination content, development, and administration.

    4.4 Examination cut score.

4.5 Grievance and disciplinary processes.

4.6 Governing body and subgroup(s)' meeting rules including agenda, frequency, and related procedures.

4.7 Subgroup(s) appointments and work assignments.

4.8 Publications about personnel Certification and re-Certification.

4.9 Setting fees for application, and all other services provided as a part of the personnel Certification and re-Certification activities.

4.10 Program funding, spending, and budget authority. Financial matters related to the operation of the program shall be segregated from other NERC activities.

5. The Personnel Certification Program shall utilize written procedures for the selection of members of the governing body that prohibit the governing body from selecting a majority of its successors.

6. The Personnel Certification Program shall be separate from the accreditation and education functions of NERC in related disciplines.

7. No member of the PCGC or staff member working with the Personnel Certification Program governing body shall have or exercise any authority or responsibility for compliance matters related to Reliability Standards concerning personnel Certification.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will

investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

   5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

3.2. Probation: A letter will be sent from NERC to the offender specifying:

3.2.1. The length of time of the probationary period (to be determined by the PCGC).

3.2.2. Credential will remain valid during the probationary period.

3.2.3. The probationary period does not affect the expiration date of the current certificate.

3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

3.3.1. The length of time of the probationary period (to be determined by the PCGC).

3.3.2. Credential is no longer valid.

3.3.3. Successfully passing an exam will be required to become recertified.

3.3.4. An exam will not be authorized until the revocation period expires

3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing Mechanisms

1. The Personnel Certification Program shall utilize reliable testing mechanisms to evaluate individual competence in a manner that is objective, fair to all candidates, job-related, and based on the knowledge and skill needed to function in the discipline.

2. The Personnel Certification Program shall implement a formal policy of periodic review of the testing mechanisms to ensure ongoing relevance of the mechanisms to knowledge and skill needed in the discipline.

3. The Personnel Certification Program shall utilize policies and procedures to ensure that all test administration and development materials are secure and demonstrate that these policies and procedures are consistently implemented.

4. The Personnel Certification Program shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted in the psychometric community as being fair and reasonable.

5. The Personnel Certification Program shall conduct ongoing studies to substantiate the reliability and validity of the testing mechanisms.

6. The Personnel Certification Program shall utilize policies and procedures that govern how long examination records are kept in their original format.

7. The Personnel Certification Program shall demonstrate that different forms of the testing mechanisms assess equivalent content and that candidates are not penalized for taking forms of varying difficulty.

607. Public Information About the Personnel Certification Program

1. The Personnel Certification Program shall maintain and publish publicly a System Operator Certification Program Manual describing the procedures used in examination construction and validation; all eligibility requirements and determination; fees; and examination administration documents, including: reporting of results, re-Certification requirements, and disciplinary and dispute resolution.

2. The Personnel Certification Program shall maintain and publish publicly a comprehensive summary or outline of the information, knowledge, or functions covered by each examination.

3. The Personnel Certification Program shall publish publicly and make available at least annually a summary of Certification activities for the program, including at least the following information: number of examinations delivered, the number passed, the number failed, and the number certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The Personnel Certification Program:

1. Shall not discriminate among applicants as to age, gender, race, religion, national origin, disability, or marital status and shall include a statement of non-discrimination in announcements of the program.

2. Shall comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services.

3. Shall make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants.

4. Shall implement a formal policy for the periodic review of eligibility criteria and application procedures to ensure that they are fair and equitable.

5. Shall provide competently proctored examination sites.

6. Shall uniformly report examination results to applicants in a timely manner.

7. Shall give applicants failing the examination information on general content areas of deficiency.

609. Responsibilities to the Public and to Employers of Certified Practitioners

The Personnel Certification Program:

1. Shall demonstrate that the testing mechanisms adequately measure the knowledge and skill required for entry, maintenance, and/or advancement in the profession for each position to be certified.

2. Shall award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable.

3. Shall maintain, in an electronic format, a current list of those persons certified in the programs and have policies and procedures that delineate what information about a Credential holder may be made public and under what circumstances.

4. Shall have formal policies and procedures for discipline of a Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

5. Shall demonstrate that any title or Credential awarded accurately reflects or applies to the practitioner's daily occupational or professional duties and is not confusing to employers, consumers, regulators, related professions, and/or other interested parties.

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

   1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

   1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

   1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

   1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

   1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems, operational readiness of the affected Regional Entities for the upcoming season

shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Maintaining the reliability of the Bulk Electric System through implementation of the Reliability Standards requires informed and trained personnel. The training and education program will provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the Bulk Electric System.

NERC shall develop and maintain training and education programs for the purpose of establishing training requirements, developing materials, and developing training activities. The target audience of the training and education programs shall be Bulk Power System operating personnel including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, training personnel, and other personnel directly responsible for complying with NERC Reliability Standards who, through their actions or inactions, may impact the real-time, or day-ahead reliability of the Bulk Power System.

NERC shall also develop and provide appropriate training and education for industry participants and regulators affected by new or changed Reliability Standards or compliance Requirements.

To accomplish those objectives:

1. NERC shall periodically conduct job task analyses for targeted Bulk Power System personnel to ensure that the training program content is properly aligned to the job tasks performed by those personnel.

2. NERC shall develop and maintain personnel training program curriculum requirements based on valid job-task analysis.

3. NERC shall periodically conduct performance surveys to determine the effectiveness of the training program and identify areas for further training development and improvement.

4. NERC shall develop training and education materials and activities to assist Bulk Power System entities implementing new or revised Reliability Standard Requirements or other NERC-related changes.

5. NERC shall develop and provide training to people who participate in NERC and Regional Entity evaluations, audits, and investigations for the Compliance Monitoring and Enforcement Program, Organization Certification Program, and the continuing education program.

902. Continuing Education Program

NERC shall develop and maintain a continuing education program to foster the improvement of training and to promote quality in the training programs used by and

implemented by Bulk Power System entities. The program shall approve or accredit those activities and entities meeting NERC continuing education requirements.

1. NERC shall develop and implement continuing education program requirements that promote excellence in training programs and advance improved performance for Bulk Power System personnel identified in Section 901.

2. NERC shall develop and maintain a process to approve or accredit continuing education Providers and activities seeking approval or accreditation and meeting NERC-approved continuing education requirements.

3. NERC shall perform periodic audits on continuing education Providers and training activities to ensure that the approved or accredited Providers and training activities satisfy NERC continuing education requirements.

4. NERC shall develop and maintain an appeals process for disputed application reviews, interpretations of guidelines and standards, probation or suspension of NERC-approved Provider status, or Continuing Education Hour disputes.

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electric Sector Information Sharing and Analysis Center (ESISAC)

    1.1 NERC shall serve as the electricity sector's sector coordinator and operate its Information Sharing and Analysis Center to gather information and communicate security-related threats and incidents within the sector, with United States and Canadian government agencies, and with other Critical Infrastructure sectors.

    1.2 NERC shall improve the capability of the ESISAC to analyze security threats and incident information and provide situational assessments for the electricity sector and governments.

    1.3 NERC shall work closely with the United States Department of Homeland Security, Department of Energy, Natural Resources Canada, and Public Safety and Emergency Preparedness Canada.

    1.4 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.5 NERC shall fill the role of the Electricity Sector Coordinating Council and coordinate with the Government Coordinating Council.

    1.6 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, the other ISACs, and the National Infrastructure Advisory Committee.

    1.7 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, and recognizing that mitigation and recovery can be practical alternatives to prevention.

2.2 NERC shall keep abreast of the changing threat environment through collaboration with government agencies.

2.3 NERC shall develop criteria to identify critical physical assets and Critical Cyber Assets, assess security threats, identify risk assessment methodologies, and assess effectiveness of physical and cyber protection measures.

2.4 NERC shall enhance and maintain the Bulk Power System critical spare transformer program, encourage increased participation by asset owners, and continue to assess the need to expand this program to include other critical Bulk Power System equipment.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness and respond to the needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters; work with DOE and DHS to implement the National Infrastructure Protection Plan, as applicable to the electricity sector; and coordinate this work with PSEPC.

2.10 NERC shall improve methods to better assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

2.11 NERC shall assess the results of vulnerability assessments and enhance the security of system control and data acquisition (SCADA) and process control systems by developing methods to detect an emerging cyber attack and the means to mitigate impacts on the Bulk Power Systems.

2.12 NERC shall work with the National SCADA Test Bed and the Process Control Systems Forum to accelerate the development of technology that

will enhance the security, safety, and reliability of process control and SCADA systems.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources

provided for in the budget to carry out the ERO program responsibilities; explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding requirement (including Regional Entity costs for delegated functions), and (3) the

mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[3] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional Entity will collect directly from the Load-Serving Entities or as otherwise

[3] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may

request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional

information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted

on NERC's website at approximately the same time that notice is given to committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

4. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

5. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the "Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or

any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement in a form approved by NERC's Board of Trustees.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief

executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Confirmed Violations** — Nothing in this Section 1500 shall prohibit the disclosure of a violation at the point when the matter is filed with an Applicable Governmental Authority as a Notice of Penalty, the "violator" admits to the violation, or the alleged violator and NERC or the Regional Entity reach a settlement regarding the violation.

2. **Compliance Information** — NERC and the Regional Entities are authorized to exchange Confidential Information related to evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses information determined to be confidential may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500

precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information,"

"aggregating" or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is

reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

   2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

   2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

   2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DEFINITIONS USED IN THE RULES OF PROCEDURE

APPENDIX 2 TO THE RULES OF PROCEDURE

Effective: TBD

General

For purposes of the NERC Rules of Procedure, including all Appendices, the terms defined in this Appendix shall have the meanings set forth herein. For convenience of reference to the user, definitions of terms that are used in a particular Appendix may be repeated in that Appendix.

Where used in the Rules of Procedure, a defined term will be capitalized. Where a term defined in this Appendix appears in the Rules of Procedure but is not capitalized, the term is there being used in its ordinary and commonly understood meaning and not as defined in this Appendix (if different). Other terms that are not defined terms, such as the names of entities, organizations, committees, or programs; position titles; titles of documents or forms; section headings; geographic locations; and other terms commonly presented as proper nouns, may also be capitalized in the Rules of Procedure without being defined in this Appendix.

Definitions of terms in this Appendix that are marked with asterisks (**) are taken from the NERC *Glossary of Terms Used in Reliability Standards*. Definitions of terms in this Appendix that are marked with "pluses" (++) are taken from Section 215 of the Federal Power Act or the Commission's regulations at 18 C.F.R. Part 39 or Part 388.

Other terms used in the Rules of Procedure but not defined in this Appendix that have commonly understood and used technical meanings in the electric power industry, including applicable codes and standards, shall be construed in accordance with such commonly understood and used technical meanings.

Specific Definitions

"Acceptance of the Exception Request" or "Acceptance" means the determination that an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) contains all the Required Information so that it can undergo substantive review.

"Adjacent Balancing Authority" means a Balancing Authority Area that is interconnected to another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**

"Adjusted Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as determined based on application of the adjustment factors identified in Section 4.3 of the *Sanction Guidelines* to the Base Penalty Amount.

"Advisories" or "Level 1 (Advisories)" is a notification issued by NERC in accordance with Section 810.3.1 of the Rules of Procedure.

"Alleged Violation" means a Possible Violation for which the Compliance Enforcement Authority has determined, based on an assessment of the facts and circumstances surrounding the Possible Violation, that evidence exists to indicate a Registered Entity has violated a Reliability Standard.

"Annual Audit Plan" means a plan developed annually by the Compliance Enforcement Authority that includes the Reliability Standards and Registered Entities to be audited and the schedule of Compliance Audits for the calendar year.

"Annual Report" means the annual report to be filed by NERC with FERC and other Applicable Governmental Authorities in accordance with Section 13.0 of Appendix 4D.

"Applicable Governmental Authority" means the FERC within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability in Canada and Mexico.

"Applicable Requirement" means a Requirement of a CIP Standard that (i) expressly provides either (A) that compliance with the terms of the Requirement is required where or as technically feasible, or (B) that technical limitations may preclude compliance with the terms of the Requirement; or (ii) is subject to Appendix 4D by FERC directive.

"Approval of the Exception Request" or "Approval" means the determination by NERC that an Exception Request meets the criteria to receive the requested Exception.

"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**

"Balancing Authority Area" means the collection of generation, transmission, and Loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains Load-resource balance within this area.**

"Base Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as initially determined pursuant to Sections 4.1 and 4.2 of the NERC *Sanction Guidelines*, before application of any adjustment factors.

"BES Definition" means the NERC definition of the Bulk Electric System as set forth in the NERC *Glossary of Terms Used in Reliability Standards.*

"Blackstart Resource" means a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.**

"Board" or "Board of Trustees" means the Board of Trustees of NERC.

"Board of Trustees Compliance Committee," "BOTCC" or "Compliance Committee" means the Compliance Committee of the NERC Board of Trustees.

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.

- **I2** - Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
    a) Gross individual nameplate rating greater than 20 MVA. Or,
    b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.

- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
    a) The individual resources, and
    b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

- **I5** - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

    a) Only serves Load. Or,

    b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

    c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

    a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

    b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

    c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4** - Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.**

"Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain

transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.

"Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada, or its designated representative(s) irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada, or its designated representative(s) irrespective of nationality; or (c) a self-representing individual who is a Canadian citizen residing in Canada.

"Canadian Entity" means a Registered Entity (or, solely for purposes of Appendix 4D, a Responsible Entity) that is organized under Canadian federal or provincial law.

"Cascading" means the uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.**

"CCC" means the NERC Compliance and Certification Committee.

"Certification" means, depending on the context, (i) the process undertaken by NERC and a Regional Entity to verify that an entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator and/or Reliability Coordinator; such Certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure; or (ii) for purposes of Section 600 of the Rules of Procedure, an official recognition that indicates the recipient has passed a NERC exam or completed a specified number of Continuing Education Hours.

"Certification Staff" means individuals employed or contracted by NERC who have the authority to make initial determinations of Certification of entities performing reliability functions.

"Certification Team" means a team assembled by a Regional Entity that will be responsible for performing the activities included in the Certification process for an entity pursuant to Appendix 5A.

"Classified National Security Information" means Required Information that has been determined to be protected from unauthorized disclosure pursuant to Executive Order No. 12958, as amended, and/or the regulations of the NRC at 10 C.F.R. §95.35; or pursuant to any comparable provision of Canadian federal or provincial law.

"Clerk" means an individual assigned by the Compliance Enforcement Authority to perform administrative tasks relating to the conduct of hearings as described in Attachment 2, Hearing Procedures, to Appendix 4C.

"Commission" means the Federal Energy Regulatory Commission or FERC.

"Complaint" means an allegation that a Registered Entity violated a Reliability Standard.

"Compliance and Certification Manager" means individual/individuals within the Regional Entity that is/are responsible for monitoring compliance of entities with applicable NERC Reliability Standards.

"Compliance Audit" means a systematic, objective review and examination of records and activities to determine whether a Registered Entity meets the Requirements of applicable Reliability Standards.

"Compliance Audit Participants" means Registered Entities scheduled to be audited and the audit team members.

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

"Compliance Enforcement Authority's Area of Responsibility" means the Compliance Enforcement Authority's Region. If a Regional Entity is the Compliance Enforcement Authority, the Compliance Enforcement Authority's Area of Responsibility is shown in Exhibit A to the delegation agreement between the Regional Entity and NERC.

"Compliance Exception" means a noncompliance that is addressed in Section 3A.0 of Appendix 4C, and is not pursued through an enforcement action under Section 5.0 of Appendix 4C to these Rules of Procedure by a Compliance Enforcement Authority.

"Compliance Investigation" means a comprehensive investigation, which may include an on-site visit with interviews of the appropriate personnel, to determine if a violation of a Reliability Standard has occurred.

"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC *Uniform Compliance Monitoring and Enforcement Program* (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

"Compliant Date" means the date by which a Responsible Entity is required to be in compliance with an Applicable Requirement of a CIP Standard.

"Confidential Business and Market Information" means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

"Confidential Information" means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the

course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition; or (vii) for purposes of Appendix 4D, any other information that is designated as Confidential Information in Section 11.0 of Appendix 4D.

"Confirmed Violation" means an Alleged Violation for which (1) the Registered Entity has accepted or not contested the Notice of Alleged Violation and Penalty or Sanction or other notification of the Alleged Violation, or (2) there has been the issuance of a final order from NERC or a Regional Entity Hearing Body finding a violation, Penalty or sanction, or (3) the period for requesting a hearing or an appeal has expired, or (4) the Registered Entity has executed a settlement agreement pursuant to Section 5.6.

"Continuing Education Hour" or "CE Hour" means based on sixty clock minutes, and includes at least fifty minutes of participation in a group or self-study learning activity that meets the criteria of the NERC Continuing Education Program.

"Continuing Education Program Provider" or "Provider" means the individual or organization offering a learning activity to participants and maintaining documentation required by Section 600 of the Rules of Procedure.

"Coordinated Functional Registration" means where two or more entities (parties) agree in writing upon a division of compliance responsibility among the parties for one or more Reliability Standard(s) applicable to a particular function, and/or for one or more Requirement(s)/sub-Requirement(s) within particular Reliability Standard(s).

"Covered Asset" means a Cyber Asset or Critical Cyber Asset that is subject to an Applicable Requirement.

"Credential" means a NERC designation that indicates the level of qualification achieved (i.e., reliability operator; balancing, interchange, and transmission operator; balancing and interchange operator; and transmission operator).

"Critical Assets" means Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.**

"Critical Cyber Assets" means Cyber Assets critical to the reliable operation of Critical Assets.**

"Critical Energy Infrastructure Information" means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.++

"Critical Infrastructure" means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.++

"Critical Infrastructure Protection Standard" or "CIP Standard" means any of NERC Reliability Standards CIP-002 through CIP-009.

"Cross-Border Regional Entity" means a Regional Entity that encompasses a part of the United States and a part of Canada or Mexico.++

"Cyber Assets" means programmable electronic devices and communication networks including hardware, software, and data.**

"Cyber Security Incident" means any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.++

"Cyber Security Incident Information" means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

"Days", as used in Appendix 5A with respect to the Registration and Certification processes, means calendar days.

"Deactivation," as used in Appendix 5A with respect to the Registration processes, refers to removal of an entity from the NCR for a specific functional category. As a result of deactivation, the entity is no longer subject to any prospective compliance obligations with respect to Reliability Standards applicable to that functional category.

"Delegate" means a person to whom the Senior Manager of a Responsible Entity has delegated authority pursuant to Requirement R2.3 of CIP Standard CIP-003-1 (or any successor provision).

"Director of Compliance" means the Director of Compliance of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Compliance Staff, or his or her designee.

"Disapproval of the Exception Request" or "Disapproval" means the determination by NERC that an Exception Request does not meet the criteria to receive the requested Exception.

"Distribution Factor" means the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).**

"Distribution Provider" means the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus,

the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**

"Document" means, in addition to the commonly understood meaning of the term as information written or printed on paper, any electronically stored information, including writings, drawings, graphs, charts, photographs, sound recordings, images and other data or data compilations stored in any medium from which information can be obtained, and shall be translated by the producing party into reasonably usable form.

"Effective Date" means the date, as specified in a notice disapproving a TFE Request or terminating an approved TFE, on which the disapproval or termination becomes effective.

"Electric Reliability Organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the Bulk Power System in the United States, subject to Commission review. The organization may also have received recognition by Applicable Governmental Authorities in Canada and Mexico to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries.

"Element" means any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.**

"Eligible Reviewer" means a person who has the required security clearances or other qualifications, or who otherwise meets the applicable criteria, to have access to Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information, as applicable to the particular information to be reviewed.

"End Date" means the last date of the period to be covered in a Compliance Audit.

"Essential Actions" or "Level 3 (Essential Actions)" is a notification issued by NERC in accordance with Section 810.3.3 of the Rules of Procedure.

"Evidentiary Hearing" means a hearing at which one or more Participants submits evidence for the record. A Testimonial Hearing is an Evidentiary Hearing, but an Evidentiary Hearing does not necessarily include the presentation of testimony by witnesses in person.

"Exception" means either an Inclusion Exception or an Exclusion Exception.

"Exception Procedure" means the procedure set forth in Appendix 5C.

"Exception Report" means information provided to the Compliance Enforcement Authority by a Registered Entity indicating that a violation of a Reliability Standard has occurred (e.g., a System Operating Limit has been exceeded) or enabling the Compliance Enforcement Authority to ascertain the Registered Entity's compliance.

"Exception Request" means a request made by a Submitting Entity in accordance with Appendix 5C for an Exception.

"Exception Request Form" means the form adopted by each Regional Entity, in accordance with a template provided by NERC, for use by Submitting Entities in submitting Exception Requests; provided, that the Exception Request Form must include Section III.B as adopted by NERC.

"Exclusion Exception" means a determination that an Element that falls within the BES Definition should be excluded from the BES.

"Expiration Date" means the date on which an approved TFE expires.

"Facility" means a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)**

"FERC" means the United States Federal Energy Regulatory Commission.

"Final Penalty Amount" means the final, proposed Penalty for violation of a Reliability Standard, determined in accordance with the *Sanction Guidelines*.

"Find, Fix, Track~~,~~ and Report" or "FFT" means a streamlined process, addressed in Section ~~3A.0~~5.2A of Appendix 4C, to resolve ~~lesser risk~~minimal or moderate risk, remediated Possible Violations that are not assessed a financial penalty.

"Flowgate" means 1.) A portion of the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.**

"FOIA" means the U.S. Freedom of Information Act, 5 U.S.C. §552.

"Footprint" means the geographical or electric area served by an entity.
"Functional Entity" means an entity responsible for a function that is required to ensure the Reliable Operation of the electric grid as identified in the NERC Reliability Standards.

"Generator Operator" means the entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.

"Generator Owner" means an entity that owns and maintains generating Facility(ies).

"Hearing Body" or "Regional Entity Hearing Body" means the body established or designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

"Hearing Officer" means, depending on the context, (i) an individual employed or contracted by the Compliance Enforcement Authority and designated by the Compliance Enforcement Authority to preside over hearings conducted pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, or (ii) solely for hearings conducted pursuant to Appendix 4E, (A) a CCC member or (B) an individual employed or contracted by NERC, as designated and approved by the CCC to preside over hearings conducted pursuant to the Hearing Procedures in Appendix E; the Hearing Officer shall not be a member of the Hearing Panel.

"Hearing Panel" means the five person hearing body established as set forth in the CCC Charter on a case by case basis and that is responsible for adjudicating a matter as set forth in Appendix 4E.

"Hearing Procedures" means, depending on the context, (i) Attachment 2 to the NERC or a Regional Entity CMEP, as applicable, or (ii) the hearing procedures of the NERC Compliance and Certification Committee in Appendix 4E.

"Inclusion Exception" means a determination that an Element that falls outside the BES Definition should be included in the BES.

"Inherent Risk Assessment" or "IRA" means a review ~~of~~ by the Compliance Enforcement Authority of potential risks posed by an individual Registered Entity to the reliability of the Bulk Power System. An IRA considers factors such as, but is not limited to, assets, system, geography, interconnectivity, prior compliance history and factors unique to the Registered Entity. The results of an entity-specific IRA may result in the scope of compliance monitoring for a particular Registered Entity to include more, fewer, or different Reliability Standards than those contained in the annual Implementation Plans.

"Interchange" means energy transfers that cross Balancing Authority boundaries.**

"Interchange Authority" means the responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communications of Interchange information for reliability assessment purposes.**

"Interchange Distribution Calculator" means the mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.**

"Interchange Schedule" means an agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.**

"Interchange Transaction" means an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.**

"Interconnected Operations Service" means a service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.**

"Interconnection" means a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++

"Interconnection Reliability Operating Limit" means a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.**

"Internal Control Evaluation" or "ICE" means a review by the Compliance Enforcement Authority of a Registered Entity's internal controls. The ICE may further refine the compliance oversight plan, including the scope of an audit, the type and application of compliance monitoring tools, the depth and breadth of a particular area of review~~, or determine whether an audit is necessary if the Registered Entity demonstrates effective internal controls~~.

"Interpretation" means an addendum to a Reliability Standard, developed in accordance with the NERC *Standard Processes Manual* and approved by the Applicable Governmental Authority(ies), that provides additional clarity about one or more Requirements in the Reliability Standard.

"ISO/RTO" means an independent transmission system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.

"Joint Registration Organization" means an entity that registers in the Compliance Registry to perform reliability functions for itself and on behalf of one or more of its members or related entities for which such members or related entities would otherwise be required to register.

"Lead Entity" means the entity that submits Exception Request information that is common to a group of Submitting Entities that are submitting Exception Requests jointly.

"Lead Mediator" means a member of a mediation team formed pursuant to Appendix 4E who is selected by the members to coordinate the mediation process and serve as the mediation team's primary contact with the Parties.

"Load" means an end-user device or customer that receives power from the electric system.**

"Load-Serving Entity" means an entity that secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.**

"Mapping" means the process of determining whether a Regional Entity's Footprint is being served by Registered Entities.

"Material Change" means a change in facts that modifies Required Information in connection with an approved TFE. Examples of a Material Change could include, but are not limited to an increase in device count (but not a decrease), change in compensating measures, change in statement of basis for approval for the TFE, a change in the Expiration Date of the TFE, or a Responsible Entity achieving Strict Compliance with the Applicable Requirement.

"Material Change Report" means a report submitted by the Responsible Entity to the Regional Entity in the event there is a Material Change to the facts underlying an approved TFE pursuant to Section 4.0 of Appendix 4D.

"Mediation Settlement Agreement" means a written agreement entered into by the Parties to a mediation pursuant to Appendix 4E that resolves the dispute.

"Member" means a member of NERC pursuant to Article II of its Bylaws.

"Member Representatives Committee" or "MRC" means the body established pursuant to Article VIII of the NERC Bylaws.

"Mexican Entity" means a Registered Entity that is organized under Mexican law.

"Mitigating Activities" means actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a Mitigation Plan.

"Mitigation Plan" means an action plan developed by the Registered Entity to (1) correct a violation of a Reliability Standard and (2) prevent re-occurrence of the violation.

"NERC-Approved Learning Activity" means training that maintains or improves professional competence and has been approved by NERC for use in its Continuing Education Program.

"NERC Compliance Monitoring and Enforcement Program Implementation Plan" or "NERC Implementation Plan" means the annual NERC ~~Compliance Monitoring and Enforcement Program~~ Implementation Plan that ~~specifies the Reliability Standards that are subject to reporting~~identifies the risk elements to prioritize risks to the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements become inputs for Regional Entities in developing their Regional Compliance Monitoring and Enforcement Program Implementation Plans and the compliance oversight for individual ~~by~~ Registered Entities ~~to the Compliance Enforcement Authority in order to verify compliance and identifies the appropriate monitoring procedures and reporting schedules for each such Reliability Standard~~. The NERC Implementation Plan may be updated more often than annually as needed.

"NERC Compliance Registry," "Compliance Registry" or "NCR" means a list, maintained by NERC pursuant to Section 500 of the NERC Rules of Procedure and Appendix 5B, the NERC *Statement of Compliance Registry Criteria*, of the owners, operators and users of the Bulk Power System, and the entities registered as their designees, that perform one or more functions in

support of reliability of the Bulk Power System and are required to comply with one or more Requirements of Reliability Standards.

"NERC Identification Number" or "NERC ID" means a number given to NERC Registered Entities that will be used to identify the entity for certain NERC activities. Corporate entities may have multiple NERC IDs to show different corporate involvement in NERC activities.

"NERC Organization Certification" or "Organization Certification" means the process undertaken by NERC and a Regional Entity to verify that a new entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator, and/or Reliability Coordinator; such certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure.

"Net Energy for Load" or "NEL" means net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.

"Notice of Alleged Violation and Proposed Penalty or Sanction" means a notice issued by the Compliance Enforcement Authority to a Registered Entity pursuant to Section 5.3 of Appendix 4C.

"Notice of Completion of Enforcement Action" means a notice issued by the Compliance Enforcement Authority to a Registered Entity, pursuant to Section 5.10 of Appendix 4C, stating than an enforcement action is closed.

"Notice of Confirmed Violation" means a notice issued by the Compliance Enforcement Authority to a Registered Entity confirming the violation of one or more Reliability Standards.

"Notice of Penalty" means a notice prepared by NERC and filed with FERC, following approval by NERC of a Notice or other notification of Confirmed Violation or a settlement agreement, stating the Penalty or sanction imposed or agreed to for the Confirmed Violation or as part of the settlement.

"Notice of Possible Violation" means a notice issued by the Compliance Enforcement Authority to a Registered Entity that (1) states a Possible Violation has been identified, (2) provides a brief description of the Possible Violation, including the Reliability Standard Requirement(s) and the date(s) involved, and (3) instructs the Registered Entity to retain and preserve all data and records relating to the Possible Violation.

"NRC" means the United States Nuclear Regulatory Commission.

"NRC Safeguards Information" means Required Information that is subject to restrictions on disclosure pursuant to 42 U.S.C. §2167 and the regulations of the NRC at 10 C.F.R. §73.21-73.23; or pursuant to comparable provisions of Canadian federal or provincial law.

"Open Access Transmission Tariff" means an electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.**

"Owner" means the owner(s) of an Element or Elements that is or may be determined to be part of the BES as a result of either the application of the BES Definition or an Exception, or another entity, such as an operator, authorized to act on behalf of the owner of the Element or Elements in the context of an Exception Request.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Body or by FERC to participate as an intervenor in a proceeding conducted pursuant to the Hearing Procedures, and as used in the Hearing Procedures shall include, depending on the context, the members of the Compliance Staff that participate in a proceeding or the members of the Certification Staff that participate in a proceeding pursuant to Appendix 4E.

"Party" or "Parties" means a Person or the Persons participating in a mediation pursuant to Appendix 4E.

"Penalty" means and includes all penalties and sanctions, including but not limited to a monetary or non-monetary penalty; a limitation on an activity, function, operation or other appropriate sanction; or the addition of the Registered Entity or Respondent to a reliability watch list composed of major violators. Penalties must be within the range set forth in the NERC *Sanction Guidelines* approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2), and shall bear a reasonable relation to the seriousness of a Registered Entity's or Respondent's violation and take into consideration any timely efforts made by the Registered Entity or Respondent to remedy the violation.

"Periodic Data Submittals" means modeling, studies, analyses, documents, procedures, methodologies, operating data, process information or other information to demonstrate compliance with Reliability Standards and provided by Registered Entities to the Compliance Enforcement Authority on a time frame required by a Reliability Standard or an ad hoc basis.

"Person" means any individual, partnership, corporation, limited liability company, governmental body, association, joint stock company, public trust, organized group of persons, whether incorporated or not, or any other legal entity.
"Planning Authority" means the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.**

"Point of Delivery" means a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.**

"Point of Receipt" means a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.

"Possible Violation" means the identification, by the Compliance Enforcement Authority, of a possible failure by a Registered Entity to comply with a Reliability Standard that is applicable to the Registered Entity.

"Preliminary Screen" means an initial evaluation of evidence indicating potential noncompliance with a Reliability Standard has occurred or is occurring, conducted by the Compliance Enforcement Authority for the purpose of determining whether a Possible Violation exists, and consisting of an evaluation of whether (1) the entity allegedly involved in the potential noncompliance is registered, (2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to a reliability function for which the entity is registered, and (3) if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation which is currently being processed.

"Probation" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is still valid. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

"Protected FOIA Information" means Required Information, held by a governmental entity, that is subject to an exemption from disclosure under FOIA (5 U.S.C. §552(e)), under any similar state or local statutory provision, or under any comparable provision of Canadian federal or provincial law, which would be lost were the Required Information to be placed into the public domain.

"Protection System" means protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**

"Purchasing-Selling Entity" means the entity that purchases, or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.**

"Reactivation" refers to re-registration pursuant to the NERC Rules of Procedure Section 500 and Appendices 5A and 5B of an entity to the NCR for a specific functional category or the revocation of, or additions to, a sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements) that has been granted to an entity. Reactivation may be initiated by NERC, a Regional Entity or an entity with respect to such entity's own functional categories or sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements).

"Reactive Power" means the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive

losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).**

"Real Power" means the portion of electricity that supplies energy to the Load.**

"Receiving Entity" means NERC or a Regional Entity receiving Confidential Information from an owner, operator, or user of the Bulk Power System or from any other party.

"Recommendation" for purposes of Appendix 5C means the report to NERC containing the evaluation prepared in accordance with section 5.2 of Appendix 5C concerning whether or to what extent an Exception Request should be approved.

"Recommendations" or "Level 2 (Recommendations)" is a notification issued by NERC in accordance with Section 810.3.2 of the Rules of Procedure.

"Region" means the geographic area, as specified in a Regional Entity's delegation agreement with NERC, within which the Regional Entity is responsible for performing delegated functions.

"Regional Criteria" means reliability requirements developed by a Regional Entity that are necessary to implement, to augment, or to comply with Reliability Standards, but which are not Reliability Standards. Such Regional Criteria may be necessary to account for physical differences in the Bulk Power System but are not inconsistent with Reliability Standards nor do they result in lesser reliability. Such Regional Criteria are not enforceable pursuant to NERC-delegated authorities, but may be enforced through other available mechanisms. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents.

"Regional Entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.++

"Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan" or "Regional Implementation Plan" means an annual Regional Entity plan, submitted ~~by~~ on or about October 1 of each year to NERC for approval that, in accordance with NERC Rule of Procedure Section 401.6 and the NERC ~~Compliance Monitoring and Enforcement Program~~ Implementation Plan, ~~identifies~~ includes (1) details on r~~R~~egional r~~R~~isk a~~A~~ssessment processes and results; ~~all Reliability Standards identified by NERC to be actively monitored during each year,~~ (2) ~~other~~ Reliability Standards and Requirements associated with r~~R~~egional r~~R~~isk a~~A~~ssessment results~~proposed for active monitoring by the Regional Entity;~~, (3) the methods to be used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria ~~with each Reliability Standard,~~; and (4) the Regional Entity's Annual Audit Plan.

"Regional Reliability Standard" means a type of Reliability Standard that is applicable only within a particular Regional Entity or group of Regional Entities. A Regional Reliability Standard may augment, add detail to, or implement another Reliability Standard or cover matters not addressed by other Reliability Standards. Regional Reliability Standards, upon adoption by

NERC and approval by the Applicable Governmental Authority(ies), shall be Reliability Standards and shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Registered Ballot Body" means that aggregation of all entities or individuals that qualify for one of the Segments approved by the Board of Trustees, and are registered with NERC as potential ballot participants in the voting on proposed Reliability Standards.

"Registered Entity" means an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry.

"Registration" or "Organization Registration" means the processes undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region.

"Rejection of the Exception Request" or "Rejection" means the determination that an Exception Request is not an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) or does not contain all the Required Information in accordance with section 4.5 of Appendix 5C in order to be reviewed for substance.

"Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.**

"Reliability Coordinator Area" means the collection of generation, transmission and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.**

"Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.

"Reliability Standards Development Plan" means the forward-looking plan developed by NERC on an annual basis setting forth the Reliability Standards development projects that are scheduled

to be worked on during the ensuing three-year period, as specified in Section 310 of the Rules of Procedure.

"Reliable Operation" means operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.++

"Remedial Action Directive" means an action (other than a Penalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a Registered Entity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.

"Reporting Entity" means an entity required to provide data or information requested by NERC or a Regional Entity in a request for data or information pursuant to Section 1600 of the Rules of Procedure.

"Requirement" means an explicit statement in a Reliability Standard that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement with which compliance is mandatory.

"Required Date" means the date given a Registered Entity in a notice from the Compliance Enforcement Authority by which some action by the Registered Entity is required.

"Required Information" means, as applicable, either (i) the information required to be provided in a TFE Request, as specified in Section 4.0 of Appendix 4D; or (ii) the information required to be provided in an Exception Request, as specified in section 4.0 of Appendix 5C.

"Reserve Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g. ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**

"Resource Planner" means the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.**

"Respondent" means, depending on the context, the Registered Entity, who is the subject of the Notice of Alleged Violation, contested Mitigation Plan or contested Remedial Action Directive that is the basis for the proceeding, whichever is applicable, or the Registered Entity that is the subject of the Certification decision that is the basis for a proceeding under Appendix 4E.

"Responsible Entity" means an entity that is registered for a reliability function in the NERC Compliance Registry and is responsible for complying with an Applicable Requirement, as specified in the "Applicability" section of the CIP Standard.

"Revoked" means a NERC certificate that has been suspended for more than twelve months. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified. The certificate holder will be required to pass an exam to be certified again. Any CE Hours accumulated prior to or during the revocation period will not be counted towards Credential Maintenance.

"Revoke for Cause" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is no longer valid and requiring successfully passing an exam to become certified. However, an exam will not be authorized until the revocation period expires. CE Hours earned before or during this revocation period will not be counted for maintaining a Credential.

"Scope of Responsibility" means the registered functions of a Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority and the geographical or electric region in which the Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority operates to perform its registered functions, or with respect to a Regional Entity, its Regional Entity Region.

"Section I Required Information" means Required Information that is to be provided in Section I of a Submitting Entity's Exception Request.

"Section II Required Information" means Required Information that is to be provided in Section II of a Submitting Entity's Exception Request.

"Section III Required Information" means Required Information that is to be provided in Section III of a Submitting Entity's Exception Request.

"Sector" means a group of Members of NERC that are Bulk Power System owners, operators, or users or other persons and entities with substantially similar interests, including governmental entities, as pertinent to the purposes and operations of NERC and the operation of the Bulk Power System, as defined in Article II, Section 4 of the NERC Bylaws. Each Sector shall constitute a class of Members for purposes of the New Jersey Nonprofit Corporation Act.

"Segment" means one of the subsets of the Registered Ballot Body whose members meet the qualification criteria for the subset.

"Self-Certification" means an attestation by a Registered Entity that it is compliant or non-compliant with a Reliability Standard Requirement that is the subject of the Self-Certification, or that it does not own Facilities that are subject to the Reliability Standard Requirement, or that the Reliability Standard Requirement is not applicable to the Registered Entity.

"Self-Logging" means a process by which Registered Entities found to be eligible by a Compliance Enforcement Authority, after a formal review of internal controls, record possible noncompliance on a log, in accordance with Section 3.5A of Appendix 4C, in lieu of individually submitted S~~s~~elf-R~~r~~eports of~~ing~~ each possible noncompliance.

"Self-Report" means a report by a Registered Entity stating that the Registered Entity believes it has, or may have, violated a Reliability Standard.

"Senior Manager" means the person assigned by the Responsible Entity, in accordance with CIP Standard CIP-003-1 Requirement R2 (or subsequent versions), to have overall responsibility for leading and managing the Responsible Entity's implementation of, and adherence to, the CIP Standards.

"Sink Balancing Authority" means the Balancing Authority in which the Load (sink) is located for an Interchange Transaction.**

"Source Balancing Authority" means the Balancing Authority in which the generation (source) is located for an Interchange Transaction.**

"Special Protection System" means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage Load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).**

"Spot Check" means a process in which the Compliance Enforcement Authority requests a Registered Entity to provide information (1) to support the Registered Entity's Self-Certification, Self-Report, or Periodic Data Submittal and to assess whether the Registered Entity complies with Reliability Standards, or (2) as a random check, or (3) in response to operating problems or system events.

"Staff" or "Compliance Staff" means individuals employed or contracted by NERC or the Compliance Enforcement Authority who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties and Mitigation Plans.

"Strict Compliance" means compliance with the terms of an Applicable Requirement without reliance on a Technical Feasibility Exception.

"Submitting Entity" means (i) an owner, operator, or user of the Bulk Power System or any other party that submits information to NERC or a Regional Entity that it reasonably believes contains Confidential Information or, (ii) solely for purposes of Appendix 5C, the entity that submits an Exception Request in accordance with section 4.0 of Appendix 5C.

"Suspended" means certificate status due to an insufficient number of CE Hours being submitted prior to the expiration of a certificate. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified.

"System" means a combination of generation, transmission and distribution components.**

"System Operating Limit" means the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.**

"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies NERC's or the Compliance Enforcement Authority's (as applicable) conflict of interest policy and is selected to assist in a proceeding by providing technical advice to the Hearing Officer and/or the Hearing Body or Hearing Panel.

"Technical Feasibility Exception" or "TFE" means an exception from Strict Compliance with the terms of an Applicable Requirement on grounds of technical feasibility or technical limitations in accordance with one or more of the criteria in section 3.0 of Appendix 4D.

"Technical Review Panel" means a panel established pursuant to section 5.3 of Appendix 5C.

"Termination of Credential" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure whereby a Credential is permanently Revoked.

"Testimonial Hearing" means an Evidentiary Hearing at which the witness or witnesses on behalf of one or more Participants appears in person to present testimony and be subject to cross-examination.

"TFE Request" means a request submitted by a Responsible Entity in accordance with Appendix 4D for an exception from Strict Compliance with an Applicable Requirement.

"Transmission Customer" means 1. any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. 2. Any of the following entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

"Transmission Operator" means the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.**

"Transmission Owner" means the entity that owns and maintains transmission Facilities.**

"Transmission Planner" means the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.**

"Transmission Service" means services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.**

"Transmission Service Provider" means the entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.**

"Variance" means an aspect or element of a Reliability Standard that applies only within a particular Regional Entity or group of Regional Entities, or to a particular entity or class of entities. A Variance allows an alternative approach to meeting the same reliability objective as the Reliability Standard, and is typically necessitated by a physical difference. A Variance is embodied within a Reliability Standard and as such, if adopted by NERC and approved by the Applicable Governmental Authority(ies), shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Violation Risk Factor" or "VRF" means a factor (lower, medium or high) assigned to each Requirement of a Reliability Standard to identify the potential reliability significance of noncompliance with the Requirement.

"Violation Severity Level" or "VSL" means a measure (lower, moderate, high or severe) of the degree to which compliance with a Requirement was not achieved.

"Wide Area" means the entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DEFINITIONS USED IN THE RULES OF PROCEDURE

APPENDIX 2 TO THE RULES OF PROCEDURE

Effective: TBD

General

For purposes of the NERC Rules of Procedure, including all Appendices, the terms defined in this Appendix shall have the meanings set forth herein. For convenience of reference to the user, definitions of terms that are used in a particular Appendix may be repeated in that Appendix.

Where used in the Rules of Procedure, a defined term will be capitalized. Where a term defined in this Appendix appears in the Rules of Procedure but is not capitalized, the term is there being used in its ordinary and commonly understood meaning and not as defined in this Appendix (if different). Other terms that are not defined terms, such as the names of entities, organizations, committees, or programs; position titles; titles of documents or forms; section headings; geographic locations; and other terms commonly presented as proper nouns, may also be capitalized in the Rules of Procedure without being defined in this Appendix.

Definitions of terms in this Appendix that are marked with asterisks (**) are taken from the NERC *Glossary of Terms Used in Reliability Standards*. Definitions of terms in this Appendix that are marked with "pluses" (++) are taken from Section 215 of the Federal Power Act or the Commission's regulations at 18 C.F.R. Part 39 or Part 388.

Other terms used in the Rules of Procedure but not defined in this Appendix that have commonly understood and used technical meanings in the electric power industry, including applicable codes and standards, shall be construed in accordance with such commonly understood and used technical meanings.

Specific Definitions

"Acceptance of the Exception Request" or "Acceptance" means the determination that an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) contains all the Required Information so that it can undergo substantive review.

"Adjacent Balancing Authority" means a Balancing Authority Area that is interconnected to another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**

"Adjusted Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as determined based on application of the adjustment factors identified in Section 4.3 of the *Sanction Guidelines* to the Base Penalty Amount.

"Advisories" or "Level 1 (Advisories)" is a notification issued by NERC in accordance with Section 810.3.1 of the Rules of Procedure.

"Alleged Violation" means a Possible Violation for which the Compliance Enforcement Authority has determined, based on an assessment of the facts and circumstances surrounding the Possible Violation, that evidence exists to indicate a Registered Entity has violated a Reliability Standard.

"Annual Audit Plan" means a plan developed annually by the Compliance Enforcement Authority that includes the Reliability Standards and Registered Entities to be audited and the schedule of Compliance Audits for the calendar year.

"Annual Report" means the annual report to be filed by NERC with FERC and other Applicable Governmental Authorities in accordance with Section 13.0 of Appendix 4D.

"Applicable Governmental Authority" means the FERC within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability in Canada and Mexico.

"Applicable Requirement" means a Requirement of a CIP Standard that (i) expressly provides either (A) that compliance with the terms of the Requirement is required where or as technically feasible, or (B) that technical limitations may preclude compliance with the terms of the Requirement; or (ii) is subject to Appendix 4D by FERC directive.

"Approval of the Exception Request" or "Approval" means the determination by NERC that an Exception Request meets the criteria to receive the requested Exception.

"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.**

"Balancing Authority Area" means the collection of generation, transmission, and Loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains Load-resource balance within this area.**

"Base Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as initially determined pursuant to Sections 4.1 and 4.2 of the NERC *Sanction Guidelines*, before application of any adjustment factors.

"BES Definition" means the NERC definition of the Bulk Electric System as set forth in the NERC *Glossary of Terms Used in Reliability Standards.*

"Blackstart Resource" means a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.**

"Board" or "Board of Trustees" means the Board of Trustees of NERC.

"Board of Trustees Compliance Committee," "BOTCC" or "Compliance Committee" means the Compliance Committee of the NERC Board of Trustees.

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.

- **I2** - Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
    a) Gross individual nameplate rating greater than 20 MVA. Or,
    b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.

- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
    a) The individual resources, and
    b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

- **I5** - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

    a) Only serves Load. Or,

    b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

    c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

    a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

    b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

    c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4** - Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.**

"Bulk Power System" means, depending on the context: (i) Facilities and control systems necessary for operating an interconnected electric energy supply and transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain

transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (ii) Solely for purposes of Appendix 4E, Bulk Electric System.

"Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada, or its designated representative(s) irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada, or its designated representative(s) irrespective of nationality; or (c) a self-representing individual who is a Canadian citizen residing in Canada.

"Canadian Entity" means a Registered Entity (or, solely for purposes of Appendix 4D, a Responsible Entity) that is organized under Canadian federal or provincial law.

"Cascading" means the uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.**

"CCC" means the NERC Compliance and Certification Committee.

"Certification" means, depending on the context, (i) the process undertaken by NERC and a Regional Entity to verify that an entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator and/or Reliability Coordinator; such Certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure; or (ii) for purposes of Section 600 of the Rules of Procedure, an official recognition that indicates the recipient has passed a NERC exam or completed a specified number of Continuing Education Hours.

"Certification Staff" means individuals employed or contracted by NERC who have the authority to make initial determinations of Certification of entities performing reliability functions.

"Certification Team" means a team assembled by a Regional Entity that will be responsible for performing the activities included in the Certification process for an entity pursuant to Appendix 5A.

"Classified National Security Information" means Required Information that has been determined to be protected from unauthorized disclosure pursuant to Executive Order No. 12958, as amended, and/or the regulations of the NRC at 10 C.F.R. §95.35; or pursuant to any comparable provision of Canadian federal or provincial law.

"Clerk" means an individual assigned by the Compliance Enforcement Authority to perform administrative tasks relating to the conduct of hearings as described in Attachment 2, Hearing Procedures, to Appendix 4C.

"Commission" means the Federal Energy Regulatory Commission or FERC.

"Complaint" means an allegation that a Registered Entity violated a Reliability Standard.

"Compliance and Certification Manager" means individual/individuals within the Regional Entity that is/are responsible for monitoring compliance of entities with applicable NERC Reliability Standards.

"Compliance Audit" means a systematic, objective review and examination of records and activities to determine whether a Registered Entity meets the Requirements of applicable Reliability Standards.

"Compliance Audit Participants" means Registered Entities scheduled to be audited and the audit team members.

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

"Compliance Enforcement Authority's Area of Responsibility" means the Compliance Enforcement Authority's Region. If a Regional Entity is the Compliance Enforcement Authority, the Compliance Enforcement Authority's Area of Responsibility is shown in Exhibit A to the delegation agreement between the Regional Entity and NERC.

"Compliance Exception" means a noncompliance that is addressed in Section 3A.0 of Appendix 4C, and is not pursued through an enforcement action under Section 5.0 of Appendix 4C to these Rules of Procedure by a Compliance Enforcement Authority.

"Compliance Investigation" means a comprehensive investigation, which may include an on-site visit with interviews of the appropriate personnel, to determine if a violation of a Reliability Standard has occurred.

"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC *Uniform Compliance Monitoring and Enforcement Program* (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

"Compliant Date" means the date by which a Responsible Entity is required to be in compliance with an Applicable Requirement of a CIP Standard.

"Confidential Business and Market Information" means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

"Confidential Information" means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the

course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition; or (vii) for purposes of Appendix 4D, any other information that is designated as Confidential Information in Section 11.0 of Appendix 4D.

"Confirmed Violation" means an Alleged Violation for which (1) the Registered Entity has accepted or not contested the Notice of Alleged Violation and Penalty or Sanction or other notification of the Alleged Violation, or (2) there has been the issuance of a final order from NERC or a Regional Entity Hearing Body finding a violation, Penalty or sanction, or (3) the period for requesting a hearing or an appeal has expired, or (4) the Registered Entity has executed a settlement agreement pursuant to Section 5.6.

"Continuing Education Hour" or "CE Hour" means based on sixty clock minutes, and includes at least fifty minutes of participation in a group or self-study learning activity that meets the criteria of the NERC Continuing Education Program.

"Continuing Education Program Provider" or "Provider" means the individual or organization offering a learning activity to participants and maintaining documentation required by Section 600 of the Rules of Procedure.

"Coordinated Functional Registration" means where two or more entities (parties) agree in writing upon a division of compliance responsibility among the parties for one or more Reliability Standard(s) applicable to a particular function, and/or for one or more Requirement(s)/sub-Requirement(s) within particular Reliability Standard(s).

"Covered Asset" means a Cyber Asset or Critical Cyber Asset that is subject to an Applicable Requirement.

"Credential" means a NERC designation that indicates the level of qualification achieved (i.e., reliability operator; balancing, interchange, and transmission operator; balancing and interchange operator; and transmission operator).

"Critical Assets" means Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.**

"Critical Cyber Assets" means Cyber Assets critical to the reliable operation of Critical Assets.**

"Critical Energy Infrastructure Information" means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.++

"Critical Infrastructure" means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.++

"Critical Infrastructure Protection Standard" or "CIP Standard" means any of NERC Reliability Standards CIP-002 through CIP-009.

"Cross-Border Regional Entity" means a Regional Entity that encompasses a part of the United States and a part of Canada or Mexico.++

"Cyber Assets" means programmable electronic devices and communication networks including hardware, software, and data.**

"Cyber Security Incident" means any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.++

"Cyber Security Incident Information" means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

"Days", as used in Appendix 5A with respect to the Registration and Certification processes, means calendar days.

"Deactivation," as used in Appendix 5A with respect to the Registration processes, refers to removal of an entity from the NCR for a specific functional category. As a result of deactivation, the entity is no longer subject to any prospective compliance obligations with respect to Reliability Standards applicable to that functional category.

"Delegate" means a person to whom the Senior Manager of a Responsible Entity has delegated authority pursuant to Requirement R2.3 of CIP Standard CIP-003-1 (or any successor provision).

"Director of Compliance" means the Director of Compliance of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Compliance Staff, or his or her designee.

"Disapproval of the Exception Request" or "Disapproval" means the determination by NERC that an Exception Request does not meet the criteria to receive the requested Exception.

"Distribution Factor" means the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).**

"Distribution Provider" means the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus,

the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**

"Document" means, in addition to the commonly understood meaning of the term as information written or printed on paper, any electronically stored information, including writings, drawings, graphs, charts, photographs, sound recordings, images and other data or data compilations stored in any medium from which information can be obtained, and shall be translated by the producing party into reasonably usable form.

"Effective Date" means the date, as specified in a notice disapproving a TFE Request or terminating an approved TFE, on which the disapproval or termination becomes effective.

"Electric Reliability Organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the Bulk Power System in the United States, subject to Commission review. The organization may also have received recognition by Applicable Governmental Authorities in Canada and Mexico to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries.

"Element" means any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.**

"Eligible Reviewer" means a person who has the required security clearances or other qualifications, or who otherwise meets the applicable criteria, to have access to Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information, as applicable to the particular information to be reviewed.

"End Date" means the last date of the period to be covered in a Compliance Audit.

"Essential Actions" or "Level 3 (Essential Actions)" is a notification issued by NERC in accordance with Section 810.3.3 of the Rules of Procedure.

"Evidentiary Hearing" means a hearing at which one or more Participants submits evidence for the record. A Testimonial Hearing is an Evidentiary Hearing, but an Evidentiary Hearing does not necessarily include the presentation of testimony by witnesses in person.

"Exception" means either an Inclusion Exception or an Exclusion Exception.

"Exception Procedure" means the procedure set forth in Appendix 5C.

"Exception Report" means information provided to the Compliance Enforcement Authority by a Registered Entity indicating that a violation of a Reliability Standard has occurred (e.g., a System Operating Limit has been exceeded) or enabling the Compliance Enforcement Authority to ascertain the Registered Entity's compliance.

"Exception Request" means a request made by a Submitting Entity in accordance with Appendix 5C for an Exception.

"Exception Request Form" means the form adopted by each Regional Entity, in accordance with a template provided by NERC, for use by Submitting Entities in submitting Exception Requests; provided, that the Exception Request Form must include Section III.B as adopted by NERC.

"Exclusion Exception" means a determination that an Element that falls within the BES Definition should be excluded from the BES.

"Expiration Date" means the date on which an approved TFE expires.

"Facility" means a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)**

"FERC" means the United States Federal Energy Regulatory Commission.

"Final Penalty Amount" means the final, proposed Penalty for violation of a Reliability Standard, determined in accordance with the *Sanction Guidelines*.

"Find, Fix, Track~~,~~ and Report" or "FFT" means a streamlined process, addressed in Section ~~3A.0~~5.2A of Appendix 4C, to resolve ~~lesser risk~~minimal or moderate risk, remediated Possible Violations that are not assessed a financial penalty.

"Flowgate" means 1.) A portion of the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.**

"FOIA" means the U.S. Freedom of Information Act, 5 U.S.C. §552.

"Footprint" means the geographical or electric area served by an entity.
"Functional Entity" means an entity responsible for a function that is required to ensure the Reliable Operation of the electric grid as identified in the NERC Reliability Standards.

"Generator Operator" means the entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.

"Generator Owner" means an entity that owns and maintains generating Facility(ies).

"Hearing Body" or "Regional Entity Hearing Body" means the body established or designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

"Hearing Officer" means, depending on the context, (i) an individual employed or contracted by the Compliance Enforcement Authority and designated by the Compliance Enforcement Authority to preside over hearings conducted pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, or (ii) solely for hearings conducted pursuant to Appendix 4E, (A) a CCC member or (B) an individual employed or contracted by NERC, as designated and approved by the CCC to preside over hearings conducted pursuant to the Hearing Procedures in Appendix E; the Hearing Officer shall not be a member of the Hearing Panel.

"Hearing Panel" means the five person hearing body established as set forth in the CCC Charter on a case by case basis and that is responsible for adjudicating a matter as set forth in Appendix 4E.

"Hearing Procedures" means, depending on the context, (i) Attachment 2 to the NERC or a Regional Entity CMEP, as applicable, or (ii) the hearing procedures of the NERC Compliance and Certification Committee in Appendix 4E.

"Inclusion Exception" means a determination that an Element that falls outside the BES Definition should be included in the BES.

"Inherent Risk Assessment" or "IRA" means a review ~~of~~ by the Compliance Enforcement Authority of potential risks posed by an individual Registered Entity to the reliability of the Bulk Power System. An IRA considers factors such as, but is not limited to, assets, system, geography, interconnectivity, prior compliance history and factors unique to the Registered Entity. The results of an entity-specific IRA may result in the scope of compliance monitoring for a particular Registered Entity to include more, fewer, or different Reliability Standards than those contained in the annual Implementation Plans.

"Interchange" means energy transfers that cross Balancing Authority boundaries.**

"Interchange Authority" means the responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communications of Interchange information for reliability assessment purposes.**

"Interchange Distribution Calculator" means the mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.**

"Interchange Schedule" means an agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.**

"Interchange Transaction" means an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.**

"Interconnected Operations Service" means a service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.**

"Interconnection" means a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.++

"Interconnection Reliability Operating Limit" means a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.**

"Internal Control Evaluation" or "ICE" means a review by the Compliance Enforcement Authority of a Registered Entity's internal controls. The ICE may further refine the compliance oversight plan, including the scope of an audit, the type and application of compliance monitoring tools, the depth and breadth of a particular area of review~~, or determine whether an audit is necessary if the Registered Entity demonstrates effective internal controls~~.

"Interpretation" means an addendum to a Reliability Standard, developed in accordance with the NERC *Standard Processes Manual* and approved by the Applicable Governmental Authority(ies), that provides additional clarity about one or more Requirements in the Reliability Standard.

"ISO/RTO" means an independent transmission system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.

"Joint Registration Organization" means an entity that registers in the Compliance Registry to perform reliability functions for itself and on behalf of one or more of its members or related entities for which such members or related entities would otherwise be required to register.

"Lead Entity" means the entity that submits Exception Request information that is common to a group of Submitting Entities that are submitting Exception Requests jointly.

"Lead Mediator" means a member of a mediation team formed pursuant to Appendix 4E who is selected by the members to coordinate the mediation process and serve as the mediation team's primary contact with the Parties.

"Load" means an end-user device or customer that receives power from the electric system.**

"Load-Serving Entity" means an entity that secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.**

"Mapping" means the process of determining whether a Regional Entity's Footprint is being served by Registered Entities.

"Material Change" means a change in facts that modifies Required Information in connection with an approved TFE. Examples of a Material Change could include, but are not limited to an increase in device count (but not a decrease), change in compensating measures, change in statement of basis for approval for the TFE, a change in the Expiration Date of the TFE, or a Responsible Entity achieving Strict Compliance with the Applicable Requirement.

"Material Change Report" means a report submitted by the Responsible Entity to the Regional Entity in the event there is a Material Change to the facts underlying an approved TFE pursuant to Section 4.0 of Appendix 4D.

"Mediation Settlement Agreement" means a written agreement entered into by the Parties to a mediation pursuant to Appendix 4E that resolves the dispute.

"Member" means a member of NERC pursuant to Article II of its Bylaws.

"Member Representatives Committee" or "MRC" means the body established pursuant to Article VIII of the NERC Bylaws.

"Mexican Entity" means a Registered Entity that is organized under Mexican law.

"Mitigating Activities" means actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a Mitigation Plan.

"Mitigation Plan" means an action plan developed by the Registered Entity to (1) correct a violation of a Reliability Standard and (2) prevent re-occurrence of the violation.

"NERC-Approved Learning Activity" means training that maintains or improves professional competence and has been approved by NERC for use in its Continuing Education Program.

"NERC Compliance Monitoring and Enforcement Program Implementation Plan" or "NERC Implementation Plan" means the annual NERC ~~Compliance Monitoring and Enforcement Program~~ Implementation Plan that ~~specifies the Reliability Standards that are subject to reporting~~identifies the risk elements to prioritize risks to the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements become inputs for Regional Entities in developing their Regional Compliance Monitoring and Enforcement Program Implementation Plans and the compliance oversight for individual ~~by~~ Registered Entities ~~to the Compliance Enforcement Authority in order to verify compliance and identifies the appropriate monitoring procedures and reporting schedules for each such Reliability Standard~~. The NERC Implementation Plan may be updated more often than annually as needed.

"NERC Compliance Registry," "Compliance Registry" or "NCR" means a list, maintained by NERC pursuant to Section 500 of the NERC Rules of Procedure and Appendix 5B, the NERC *Statement of Compliance Registry Criteria*, of the owners, operators and users of the Bulk Power System, and the entities registered as their designees, that perform one or more functions in

support of reliability of the Bulk Power System and are required to comply with one or more Requirements of Reliability Standards.

"NERC Identification Number" or "NERC ID" means a number given to NERC Registered Entities that will be used to identify the entity for certain NERC activities. Corporate entities may have multiple NERC IDs to show different corporate involvement in NERC activities.

"NERC Organization Certification" or "Organization Certification" means the process undertaken by NERC and a Regional Entity to verify that a new entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator, and/or Reliability Coordinator; such certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure.

"Net Energy for Load" or "NEL" means net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.

"Notice of Alleged Violation and Proposed Penalty or Sanction" means a notice issued by the Compliance Enforcement Authority to a Registered Entity pursuant to Section 5.3 of Appendix 4C.

"Notice of Completion of Enforcement Action" means a notice issued by the Compliance Enforcement Authority to a Registered Entity, pursuant to Section 5.10 of Appendix 4C, stating than an enforcement action is closed.

"Notice of Confirmed Violation" means a notice issued by the Compliance Enforcement Authority to a Registered Entity confirming the violation of one or more Reliability Standards.

"Notice of Penalty" means a notice prepared by NERC and filed with FERC, following approval by NERC of a Notice or other notification of Confirmed Violation or a settlement agreement, stating the Penalty or sanction imposed or agreed to for the Confirmed Violation or as part of the settlement.

"Notice of Possible Violation" means a notice issued by the Compliance Enforcement Authority to a Registered Entity that (1) states a Possible Violation has been identified, (2) provides a brief description of the Possible Violation, including the Reliability Standard Requirement(s) and the date(s) involved, and (3) instructs the Registered Entity to retain and preserve all data and records relating to the Possible Violation.

"NRC" means the United States Nuclear Regulatory Commission.

"NRC Safeguards Information" means Required Information that is subject to restrictions on disclosure pursuant to 42 U.S.C. §2167 and the regulations of the NRC at 10 C.F.R. §73.21-73.23; or pursuant to comparable provisions of Canadian federal or provincial law.

"Open Access Transmission Tariff" means an electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.**

"Owner" means the owner(s) of an Element or Elements that is or may be determined to be part of the BES as a result of either the application of the BES Definition or an Exception, or another entity, such as an operator, authorized to act on behalf of the owner of the Element or Elements in the context of an Exception Request.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Body or by FERC to participate as an intervenor in a proceeding conducted pursuant to the Hearing Procedures, and as used in the Hearing Procedures shall include, depending on the context, the members of the Compliance Staff that participate in a proceeding or the members of the Certification Staff that participate in a proceeding pursuant to Appendix 4E.

"Party" or "Parties" means a Person or the Persons participating in a mediation pursuant to Appendix 4E.

"Penalty" means and includes all penalties and sanctions, including but not limited to a monetary or non-monetary penalty; a limitation on an activity, function, operation or other appropriate sanction; or the addition of the Registered Entity or Respondent to a reliability watch list composed of major violators. Penalties must be within the range set forth in the NERC *Sanction Guidelines* approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2), and shall bear a reasonable relation to the seriousness of a Registered Entity's or Respondent's violation and take into consideration any timely efforts made by the Registered Entity or Respondent to remedy the violation.

"Periodic Data Submittals" means modeling, studies, analyses, documents, procedures, methodologies, operating data, process information or other information to demonstrate compliance with Reliability Standards and provided by Registered Entities to the Compliance Enforcement Authority on a time frame required by a Reliability Standard or an ad hoc basis.

"Person" means any individual, partnership, corporation, limited liability company, governmental body, association, joint stock company, public trust, organized group of persons, whether incorporated or not, or any other legal entity.
"Planning Authority" means the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.**

"Point of Delivery" means a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.**

"Point of Receipt" means a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.

"Possible Violation" means the identification, by the Compliance Enforcement Authority, of a possible failure by a Registered Entity to comply with a Reliability Standard that is applicable to the Registered Entity.

"Preliminary Screen" means an initial evaluation of evidence indicating potential noncompliance with a Reliability Standard has occurred or is occurring, conducted by the Compliance Enforcement Authority for the purpose of determining whether a Possible Violation exists, and consisting of an evaluation of whether (1) the entity allegedly involved in the potential noncompliance is registered, (2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to a reliability function for which the entity is registered, and (3) if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation which is currently being processed.

"Probation" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is still valid. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

"Protected FOIA Information" means Required Information, held by a governmental entity, that is subject to an exemption from disclosure under FOIA (5 U.S.C. §552(e)), under any similar state or local statutory provision, or under any comparable provision of Canadian federal or provincial law, which would be lost were the Required Information to be placed into the public domain.

"Protection System" means protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**

"Purchasing-Selling Entity" means the entity that purchases, or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.**

"Reactivation" refers to re-registration pursuant to the NERC Rules of Procedure Section 500 and Appendices 5A and 5B of an entity to the NCR for a specific functional category or the revocation of, or additions to, a sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements) that has been granted to an entity. Reactivation may be initiated by NERC, a Regional Entity or an entity with respect to such entity's own functional categories or sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements).

"Reactive Power" means the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive

losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).**

"Real Power" means the portion of electricity that supplies energy to the Load.**

"Receiving Entity" means NERC or a Regional Entity receiving Confidential Information from an owner, operator, or user of the Bulk Power System or from any other party.

"Recommendation" for purposes of Appendix 5C means the report to NERC containing the evaluation prepared in accordance with section 5.2 of Appendix 5C concerning whether or to what extent an Exception Request should be approved.

"Recommendations" or "Level 2 (Recommendations)" is a notification issued by NERC in accordance with Section 810.3.2 of the Rules of Procedure.

"Region" means the geographic area, as specified in a Regional Entity's delegation agreement with NERC, within which the Regional Entity is responsible for performing delegated functions.

"Regional Criteria" means reliability requirements developed by a Regional Entity that are necessary to implement, to augment, or to comply with Reliability Standards, but which are not Reliability Standards. Such Regional Criteria may be necessary to account for physical differences in the Bulk Power System but are not inconsistent with Reliability Standards nor do they result in lesser reliability. Such Regional Criteria are not enforceable pursuant to NERC-delegated authorities, but may be enforced through other available mechanisms. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents.

"Regional Entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.++

"Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan" or "Regional Implementation Plan" means an annual Regional Entity plan, submitted ~~by~~ on or about October 1 of each year to NERC for approval that, in accordance with NERC Rule of Procedure Section 401.6 and the NERC ~~Compliance Monitoring and Enforcement Program~~ Implementation Plan, ~~identifies~~ includes (1) details on r~~R~~egional r~~R~~isk a~~A~~ssessment processes and results; ~~all Reliability Standards identified by NERC to be actively monitored during each year,~~ (2) ~~other~~ Reliability Standards and Requirements associated with r~~R~~egional r~~R~~isk a~~A~~ssessment results~~proposed for active monitoring by the Regional Entity;~~, (3) the methods to be used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria ~~with each Reliability Standard,~~; and (4) the Regional Entity's Annual Audit Plan.

"Regional Reliability Standard" means a type of Reliability Standard that is applicable only within a particular Regional Entity or group of Regional Entities. A Regional Reliability Standard may augment, add detail to, or implement another Reliability Standard or cover matters not addressed by other Reliability Standards. Regional Reliability Standards, upon adoption by

NERC and approval by the Applicable Governmental Authority(ies), shall be Reliability Standards and shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Registered Ballot Body" means that aggregation of all entities or individuals that qualify for one of the Segments approved by the Board of Trustees, and are registered with NERC as potential ballot participants in the voting on proposed Reliability Standards.

"Registered Entity" means an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry.

"Registration" or "Organization Registration" means the processes undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region.

"Rejection of the Exception Request" or "Rejection" means the determination that an Exception Request is not an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) or does not contain all the Required Information in accordance with section 4.5 of Appendix 5C in order to be reviewed for substance.

"Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.**

"Reliability Coordinator Area" means the collection of generation, transmission and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.**

"Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.

"Reliability Standards Development Plan" means the forward-looking plan developed by NERC on an annual basis setting forth the Reliability Standards development projects that are scheduled

to be worked on during the ensuing three-year period, as specified in Section 310 of the Rules of Procedure.

"Reliable Operation" means operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements.++

"Remedial Action Directive" means an action (other than a Penalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a Registered Entity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.

"Reporting Entity" means an entity required to provide data or information requested by NERC or a Regional Entity in a request for data or information pursuant to Section 1600 of the Rules of Procedure.

"Requirement" means an explicit statement in a Reliability Standard that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement with which compliance is mandatory.

"Required Date" means the date given a Registered Entity in a notice from the Compliance Enforcement Authority by which some action by the Registered Entity is required.

"Required Information" means, as applicable, either (i) the information required to be provided in a TFE Request, as specified in Section 4.0 of Appendix 4D; or (ii) the information required to be provided in an Exception Request, as specified in section 4.0 of Appendix 5C.

"Reserve Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g. ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**

"Resource Planner" means the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.**

"Respondent" means, depending on the context, the Registered Entity, who is the subject of the Notice of Alleged Violation, contested Mitigation Plan or contested Remedial Action Directive that is the basis for the proceeding, whichever is applicable, or the Registered Entity that is the subject of the Certification decision that is the basis for a proceeding under Appendix 4E.

"Responsible Entity" means an entity that is registered for a reliability function in the NERC Compliance Registry and is responsible for complying with an Applicable Requirement, as specified in the "Applicability" section of the CIP Standard.

"Revoked" means a NERC certificate that has been suspended for more than twelve months. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified. The certificate holder will be required to pass an exam to be certified again. Any CE Hours accumulated prior to or during the revocation period will not be counted towards Credential Maintenance.

"Revoke for Cause" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is no longer valid and requiring successfully passing an exam to become certified. However, an exam will not be authorized until the revocation period expires. CE Hours earned before or during this revocation period will not be counted for maintaining a Credential.

"Scope of Responsibility" means the registered functions of a Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority and the geographical or electric region in which the Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority operates to perform its registered functions, or with respect to a Regional Entity, its Regional Entity Region.

"Section I Required Information" means Required Information that is to be provided in Section I of a Submitting Entity's Exception Request.

"Section II Required Information" means Required Information that is to be provided in Section II of a Submitting Entity's Exception Request.

"Section III Required Information" means Required Information that is to be provided in Section III of a Submitting Entity's Exception Request.

"Sector" means a group of Members of NERC that are Bulk Power System owners, operators, or users or other persons and entities with substantially similar interests, including governmental entities, as pertinent to the purposes and operations of NERC and the operation of the Bulk Power System, as defined in Article II, Section 4 of the NERC Bylaws. Each Sector shall constitute a class of Members for purposes of the New Jersey Nonprofit Corporation Act.

"Segment" means one of the subsets of the Registered Ballot Body whose members meet the qualification criteria for the subset.

"Self-Certification" means an attestation by a Registered Entity that it is compliant or non-compliant with a Reliability Standard Requirement that is the subject of the Self-Certification, or that it does not own Facilities that are subject to the Reliability Standard Requirement, or that the Reliability Standard Requirement is not applicable to the Registered Entity.

"Self-Logging" means a process by which Registered Entities found to be eligible by a Compliance Enforcement Authority, after a formal review of internal controls, record possible noncompliance on a log, in accordance with Section 3.5A of Appendix 4C, in lieu of individually submitted Sself-Rreports ofing each possible noncompliance.

"Self-Report" means a report by a Registered Entity stating that the Registered Entity believes it has, or may have, violated a Reliability Standard.

"Senior Manager" means the person assigned by the Responsible Entity, in accordance with CIP Standard CIP-003-1 Requirement R2 (or subsequent versions), to have overall responsibility for leading and managing the Responsible Entity's implementation of, and adherence to, the CIP Standards.

"Sink Balancing Authority" means the Balancing Authority in which the Load (sink) is located for an Interchange Transaction.**

"Source Balancing Authority" means the Balancing Authority in which the generation (source) is located for an Interchange Transaction.**

"Special Protection System" means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage Load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).**

"Spot Check" means a process in which the Compliance Enforcement Authority requests a Registered Entity to provide information (1) to support the Registered Entity's Self-Certification, Self-Report, or Periodic Data Submittal and to assess whether the Registered Entity complies with Reliability Standards, or (2) as a random check, or (3) in response to operating problems or system events.

"Staff" or "Compliance Staff" means individuals employed or contracted by NERC or the Compliance Enforcement Authority who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties and Mitigation Plans.

"Strict Compliance" means compliance with the terms of an Applicable Requirement without reliance on a Technical Feasibility Exception.

"Submitting Entity" means (i) an owner, operator, or user of the Bulk Power System or any other party that submits information to NERC or a Regional Entity that it reasonably believes contains Confidential Information or, (ii) solely for purposes of Appendix 5C, the entity that submits an Exception Request in accordance with section 4.0 of Appendix 5C.

"Suspended" means certificate status due to an insufficient number of CE Hours being submitted prior to the expiration of a certificate. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified.

"System" means a combination of generation, transmission and distribution components.**

"System Operating Limit" means the value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.**

"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies NERC's or the Compliance Enforcement Authority's (as applicable) conflict of interest policy and is selected to assist in a proceeding by providing technical advice to the Hearing Officer and/or the Hearing Body or Hearing Panel.

"Technical Feasibility Exception" or "TFE" means an exception from Strict Compliance with the terms of an Applicable Requirement on grounds of technical feasibility or technical limitations in accordance with one or more of the criteria in section 3.0 of Appendix 4D.

"Technical Review Panel" means a panel established pursuant to section 5.3 of Appendix 5C.

"Termination of Credential" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure whereby a Credential is permanently Revoked.

"Testimonial Hearing" means an Evidentiary Hearing at which the witness or witnesses on behalf of one or more Participants appears in person to present testimony and be subject to cross-examination.

"TFE Request" means a request submitted by a Responsible Entity in accordance with Appendix 4D for an exception from Strict Compliance with an Applicable Requirement.

"Transmission Customer" means 1. any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. 2. Any of the following entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

"Transmission Operator" means the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.**

"Transmission Owner" means the entity that owns and maintains transmission Facilities.**

"Transmission Planner" means the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.**

"Transmission Service" means services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.**

"Transmission Service Provider" means the entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.**

"Variance" means an aspect or element of a Reliability Standard that applies only within a particular Regional Entity or group of Regional Entities, or to a particular entity or class of entities. A Variance allows an alternative approach to meeting the same reliability objective as the Reliability Standard, and is typically necessitated by a physical difference. A Variance is embodied within a Reliability Standard and as such, if adopted by NERC and approved by the Applicable Governmental Authority(ies), shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Violation Risk Factor" or "VRF" means a factor (lower, medium or high) assigned to each Requirement of a Reliability Standard to identify the potential reliability significance of noncompliance with the Requirement.

"Violation Severity Level" or "VSL" means a measure (lower, moderate, high or severe) of the degree to which compliance with a Requirement was not achieved.

"Wide Area" means the entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation

Compliance Monitoring and Enforcement Program

APPENDIX 4C TO THE RULES OF PROCEDURE

Effective: TBD

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ATTACHMENT 1 – PROCESS FOR NON-SUBMITTAL OF REQUESTED DATA

ATTACHMENT 2 – COMPLIANCE ENFORCEMENT AUTHORITY HEARING PROCEDURE

COMPLIANCE MONITORING AND ENFORCEMENT PROGRAM

1.0 INTRODUCTION

This Compliance Monitoring and Enforcement Program ("Compliance Program") is the program to be used by the North American Electric Reliability Corporation ("NERC") and the Regional Entities to monitor, assess, and enforce compliance with Reliability Standards within the United States. Compliance Monitoring and Enforcement Programs also will be implemented in Canada consistent with Canadian laws and agreements.

1.1 Definitions

Capitalized terms used in this Compliance Program shall have the meanings set forth in Appendix 2 of the NERC Rules of Procedure. ~~For convenience of reference, defined terms frequently used in this Appendix are also set forth below:~~

~~Alleged Violation: A Possible Violation for which the Compliance Enforcement Authority has determined, based on an assessment of the facts and circumstances surrounding the Possible Violation, that evidence exists to indicate a Registered Entity has violated a Reliability Standard.~~

~~Annual Audit Plan: A plan developed annually by the Compliance Enforcement Authority that includes the Reliability Standards and Registered Entities to be audited and the schedule of Compliance Audits for the calendar year.~~

~~Applicable Governmental Authority: The Federal Energy Regulatory Commission ("FERC") within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability in Canada and Mexico.~~

~~Complaint: An allegation that a Registered Entity violated a Reliability Standard.~~

~~Compliance Audit: A systematic, objective review and examination of records and activities to determine whether a Registered Entity meets the Requirements of applicable Reliability Standards.~~

~~Compliance Audit Participants: Registered Entities scheduled to be audited and the audit team members.~~

~~Compliance Enforcement Authority: NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

~~Compliance Exception: A noncompliance that is addressed in Section 3A.0 of Appendix 4C, and is not pursued through an enforcement action under Section 5.0 of Appendix 4C by a Compliance Enforcement Authority.~~

~~**1.1.8**~~**9** ~~Compliance Investigation: A comprehensive investigation, which may include an on-site visit with interviews of the appropriate personnel, to determine if a violation of a Reliability Standard has occurred.~~**1.1.9** ~~—~~

~~**1.1.10** Confirmed Violation: An Alleged Violation for which (1) the Registered Entity has accepted or not contested the Notice of Alleged Violation and Proposed Penalty or Sanction or other notification of the Alleged Violation, or (2) there has been the issuance of a final order from NERC or a Regional Entity Hearing Body finding a violation, Penalty or sanction, or (3) the period for requesting a hearing or an appeal has expired, or (4) the Registered Entity has executed a settlement agreement pursuant to Section 5.6.~~

~~**1.1.10**11 End Date: The last date of the period to be covered in a Compliance Audit.~~

~~**1.1.11**12 Exception Report: Information provided to the Compliance Enforcement Authority by a Registered Entity indicating that a violation of a Reliability Standard has occurred (e.g., a System Operating Limit has been exceeded) or enabling the Compliance Enforcement Authority to ascertain the Registered Entity's compliance.~~

~~**1.1.13** Find, Fix, Track, and Report: A streamlined process, addressed in Section 3A.0 of Appendix 4C, to resolve lesser-risk, remediated Possible Violations that are not assessed a financial penalty.~~

~~**1.1.14** Inherent Risk Assessment ("IRA"): A review by the Compliance Enforcement Authority of potential risks posed by an individual Registered Entity to the reliability of the Bulk Power System. An IRA considers factors such as, but not limited to, assets, system, geography, interconnectivity, prior compliance history, and factors unique to the Registered Entity. The results of an entity-specific IRA may result in the scope of compliance monitoring for a particular Registered Entity to include more, fewer, or different Reliability Standards than those contained in the annual Implementation Plans.~~

~~**1.1.15** Internal Control Evaluation: A review by the Compliance Enforcement Authority of a Registered Entity's internal controls. The ICE may further refine the compliance oversight plan, including the scope of an audit, the type and application of compliance monitoring tools, the depth and breadth of a particular area of review, or determine whether an audit is necessary if the Registered Entity demonstrates effective internal controls.~~

~~**1.1.16**2 ISO/RTO: An independent transmission system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.~~

~~**1.1.17**3 Mitigating Activities: Actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a Mitigation Plan.~~

~~**1.1.18**4 Mitigation Plan: An action plan developed by the Registered Entity to (1) correct a violation of a Reliability Standard and (2) prevent re-occurrence of the violation.~~

~~**1.1.19**5 NERC Compliance Registry: A list, maintained by NERC pursuant to Section 500 of the NERC Rules of Procedure and Appendix 5B, the NERC *Statement of Compliance Registry Criteria*, of the owners, operators and users of the Bulk Power System, and the entities registered as their designees, that perform one or more functions in support of reliability of the Bulk Power System and are required to comply with one or more Requirements of Reliability Standards.~~

~~**1.1.16**20 NERC Compliance Monitoring and Enforcement Program Implementation Plan or NERC Implementation Plan: The annual NERC Compliance Monitoring and Enforcement~~

~~Program Implementation Plan that specifies the Reliability Standards that are subject to reporting~~identifies the risk elements to prioritize risks to the reliability of the Bulk Power System. These risk elements and related NERC Reliability Standards Requirements become inputs for Regional Entities in developing their Regional Implementation Plans and the compliance oversight plan for individual ~~by Registered Entities to the Compliance Enforcement Authority in order to verify compliance and identifies the appropriate monitoring procedures and reporting schedules for each such Reliability Standard. The NERC Implementation Plan may be updated as needed.~~

~~**1.1.17**~~**21** ~~Notice of Alleged Violation and Proposed Penalty or Sanction: A notice issued by the Compliance Enforcement Authority to a Registered Entity pursuant to Section 5.3.~~

~~**1.1.18**~~**22** ~~Notice of Completion of Enforcement Action: A notice issued by the Compliance Enforcement Authority to a Registered Entity, pursuant to Section 5.10, stating than an enforcement action is closed.~~

~~**1.1.19**~~**23** ~~Notice of Confirmed Violation: A notice issued by the Compliance Enforcement Authority to a Registered Entity confirming the violation of one or more Reliability Standards.~~

~~**1.1.20**~~**24** ~~Notice of Penalty: A notice prepared by NERC and filed with FERC, following approval by NERC of a Notice or other notification of Confirmed Violation or a settlement agreement, stating the Penalty or sanction imposed or agreed to for the Confirmed Violation or as part of the settlement.~~

~~**1.1.21**~~**25** ~~Notice of Possible Violation: A notice issued by the Compliance Enforcement Authority to a Registered Entity that (1) states a Possible Violation has been identified, (2) provides a brief description of the Possible Violation, including the Reliability Standard Requirement(s) and the date(s) involved, and (3) instructs the Registered Entity to retain and preserve all data and records relating to the Possible Violation.~~

~~**1.1.22**~~**26** ~~Periodic Data Submittals: Modeling, studies, analyses, documents, procedures, methodologies, operating data, process information or other information to demonstrate compliance with Reliability Standards and provided by Registered Entities to the Compliance Enforcement Authority on a time frame required by a Reliability Standard or an ad hoc basis.~~

~~**1.1.23**~~**27** ~~Possible Violation: The identification, by the Compliance Enforcement Authority, of a possible failure by a Registered Entity to comply with a Reliability Standard that is applicable to the Registered Entity.~~

~~**1.1.24**~~**28** ~~Preliminary Screen: An initial evaluation of evidence indicating potential noncompliance with a Reliability Standard has occurred or is occurring, conducted by the Compliance Enforcement Authority for the purpose of determining whether a Possible Violation exists, and consisting of an evaluation of whether (1) the entity allegedly involved in the potential noncompliance is registered, (2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to a reliability function for which the entity is registered, and (3) if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation which is currently being processed.~~

~~**1.1.2529** Regional Implementation Plan: An annual~~ Regional Entity plan, ~~submitted by on or about October 1 of each year to NERC for approval that, in accordance with NERC Rule of Procedure Section 401.6 and the NERC Compliance Monitoring and Enforcement Program Implementation Plan,~~ includes (1) details on Regional Risk Assessment processes and results; (2) Reliability Standards and Requirements associated with Regional Risk Assessment results; ~~identifies (1) all Reliability Standards identified by NERC to be actively monitored during each year, (2) other Reliability Standards proposed for active monitoring by the Regional Entity, (3) the methods to be used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria with each Reliability Standard;~~, and ~~(4) the Regional Entity's Annual Audit Plan.~~

~~**1.1.2630** Registered Entity: An owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry.~~

~~**1.1.2731** Remedial Action Directive: An action (other than a Penalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a Registered Entity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.~~

~~**1.1.2832** Required Date: The date given a Registered Entity in a notice from the Compliance Enforcement Authority by which some action by the Registered Entity is required.~~

~~**1.1.2933** Self-Certification: An attestation by a Registered Entity that it is compliant or non-compliant with a Reliability Standard Requirement that is the subject of the Self-Certification, or that it does not own Facilities that are subject to the Reliability Standard Requirement, or that the Reliability Standard Requirement is not applicable to the Registered Entity.~~

~~**1.1.34** Self-Logging: A process by which Registered Entities found to be eligible by a Compliance Enforcement Authority, after a formal review of internal controls, record noncompliance on a log, in accordance with Section 3.5A of Appendix 4C, in lieu of individually self-reporting each possible noncompliance.~~

~~**1.1.3035** Self-Report: A report by a Registered Entity stating that the Registered Entity believes it has, or may have, violated a Reliability Standard.~~

~~**1.1.3136** Spot Check: A process in which the Compliance Enforcement Authority requests a Registered Entity to provide information (1) to support the Registered Entity's Self-Certification, Self-Report, or Periodic Data Submittal and to assess whether the Registered Entity complies with Reliability Standards, or (2) as a random check, or (3) in response to operating problems or system events.~~

2.0 IDENTIFICATION OF ORGANIZATIONS RESPONSIBLE FOR COMPLYING WITH RELIABILITY STANDARDS

NERC shall register the organizations responsible for complying with Reliability Standards, in accordance with Section 500 of the NERC Rules of Procedure and Appendix 5B, *Statement of*

Compliance Registry Criteria. Organizations are responsible to register and to comply with Reliability Standards if they are owners, operators, and users of the Bulk Power System, perform a function listed in the functional types identified in Section II of Appendix 5B, and are material to the Reliable Operation of the Bulk Power System as defined by the criteria and notes in Appendix 5B. Regional Entities shall (i) develop and provide to NERC information to assist NERC to register organizations responsible for complying with Reliability Standards, and (ii) in the event of a Registration appeal to NERC or an Applicable Governmental Authority, provide information requested by NERC concerning how the Registered Entity meets the Registration criteria or is otherwise material to the reliability of the Bulk Power System.

NERC shall notify organizations of their inclusion on the NERC Compliance Registry and shall maintain the NERC Compliance Registry on its web site. NERC shall inform each Registered Entity at the time of Registration of the Reliability Standards that are applicable to reliability functions for which the Registered Entity is registered. Each Registered Entity shall inform NERC or the applicable Regional Entity promptly of changes to the Registered Entity's Registration information including planned or completed changes in ownership of Bulk Power System Facilities, Registration status, address and other contact information, and name of designated compliance contact. NERC will provide FERC and Applicable Governmental Authorities monthly updates to the NERC Compliance Registry.

NERC and each Regional Entity will designate a contact person(s) and require each Registered Entity to designate a contact person(s) responsible for sending and receiving all necessary information and communications concerning compliance matters. NERC and the applicable Regional Entity will designate where Registered Entities are to send information, data, Mitigation Plans, or any other compliance-related correspondence.

NERC shall maintain on its website a current listing of Reliability Standards that are applicable to all Registered Entities.

As provided for herein, during the course of compliance monitoring and enforcement activities relating to U.S. entities, NERC may obtain information that it will provide to FERC and, if the information pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority. Any such provision of information to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure.

3.0 COMPLIANCE MONITORING PROCESSES

NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify risk elements and related NERC Reliability Standards and Requirements to be considered in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan (Implementation Plan). NERC identifies the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. NERC uses these risk elements to identify and prioritize continent-wide risks to the reliability of the ~~BPS~~Bulk Power System. These identified risks represent the focus for oversight activities in the

upcoming year, and become inputs for developing oversight plans for individual Registered Entities.

The Compliance Enforcement Authority will monitor Registered Entities' compliance with Reliability Standards using the compliance monitoring processes described in this Section. A Compliance Enforcement Authority will determine the type and frequency of application of the compliance monitoring tools appropriate for a particular Registered Entity based on the Registered Entity's specific risks to the reliability of the Bulk Power System.

If a compliance monitoring process described in this Section reveals a potential noncompliance with a Reliability Standard, the Compliance Enforcement Authority will conduct a Preliminary Screen of the potential noncompliance in accordance with Section 3.8. In addition, if the Compliance Enforcement Authority obtains evidence or information of a potential noncompliance with a Reliability Standard through any other means, including but not limited to an Exception Report or other report of noncompliance that a Registered Entity is required to submit in accordance with the terms of a Reliability Standard, the Compliance Enforcement Authority will conduct a Preliminary Screen of the information in accordance with Section 3.8. If the Preliminary Screen results in an affirmative determination with respect to the Preliminary Screen criteria, a Possible Violation exists and the Compliance Enforcement Authority will proceed in accordance with Section 5.0, Enforcement Actions ~~unless an alternative enforcement process is used, in accordance with Section 3A.0~~except as otherwise authorized in these Rules of Procedure.

Registered Entities found in violation of a Reliability Standard will be required to mitigate the violation regardless of any enforcement actions taken.

The compliance monitoring processes in this Section require timely information, reports and data from Registered Entities to effectively monitor compliance with Reliability Standards. The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies of Documents, data and information to be made and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. If Documents, data, information or other reports to determine compliance requested from a Registered Entity are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel.

Any report or other submission of information by a Registered Entity required by the Compliance Program shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity. Electronic signatures are permitted in accordance with processes established by NERC and the Regional Entity. NERC or the Compliance Enforcement Authority may require the signer to provide a statement of the basis of his or her authority to sign on behalf of the Registered Entity.

3.1 Compliance Audits

All Registered Entities are subject to audit for compliance with all Reliability Standards applicable to the functions for which the Registered Entity is registered. Compliance Audits are conducted on the Registered Entity's site to the extent required by NERC Rule of Procedure 403.11.2. Compliance Audit processes for Compliance Audits conducted in the United States shall be based on professional auditing standards recognized in the U.S., which may include for example Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards and standards sanctioned by the Institute of Internal Auditors. Compliance Audit processes for Compliance Audits conducted outside the U.S. may be based on Canadian or other international standards. All Compliance Audits shall be conducted in accordance with audit guides established for the Reliability Standards included in the Compliance Audit, consistent with accepted auditing guidelines as approved by NERC. The audit guides will be posted on NERC's website.

3.1.1 Compliance Audit Process Steps

The process steps for a Compliance Audit are as follows:

- The Compliance Enforcement Authority posts the Annual Audit Plan (developed in coordination with NERC). The Compliance Enforcement Authority provides additional information to the Compliance Audit Participants, including Compliance Audit materials, coordinating agendas and changes to the Compliance Audit schedule as required. NERC or the Regional Entity provides the Compliance Audit schedules to FERC and to any other Applicable Governmental Authority based upon the agreements in place with the other Applicable Governmental Authority.

- At least ninety (90) days prior to commencement of a regularly scheduled Compliance Audit, the Compliance Enforcement Authority notifies the Registered Entity of the Compliance Audit and the Reliability Standards to be evaluated, identifies the Compliance Audit team members and their recent employment history, and requests data, including a completed NERC pre-Compliance Audit questionnaire. If the Compliance Audit team members change from the time of the original notification, the Compliance Enforcement Authority will promptly notify the Registered Entity of the change and will allow time for the Registered Entity to object to the new Compliance Audit team member(s) (see Section 3.1.5.4).

- The Registered Entity provides to the Compliance Enforcement Authority the required information in the format and by the Required Date specified in the request.

- The Compliance Audit team reviews the submitted information for conformance with the Requirements of the Reliability Standards.

- The Compliance Audit team conducts an exit briefing with the Registered Entity, provides for a review of the Compliance Audit report with the Registered Entity before it is finalized, and completes a Compliance Audit report in accordance with Section 3.1.6.

- If the Compliance Audit Team identifies evidence of a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

3.1.2 Compliance Enforcement Authority Annual Audit Plan and Schedule

The Compliance Enforcement Authority shall develop an Annual Audit Plan. The Annual Audit Plan of Regional Entities will be included in the Regional Implementation Plans submitted to NERC for review and approval (see Section 4.2). NERC or the Regional Entity provides the Annual Audit Plans to FERC and to any other Applicable Governmental Authority consistent with the agreements in place with the Applicable Governmental Authority.

Prior to October 1 of the year preceding the year covered by the Annual Audit Plan, the Compliance Enforcement Authority shall notify Registered Entities subject to Compliance Audits during the upcoming year of the Compliance Audit schedule. The Compliance Enforcement Authority will give due consideration to any schedule changes requested by Registered Entities for reasonable cause.

Revisions and additions to a Regional Entity Annual Audit Plan shall be communicated to and approved by NERC, and shall be communicated to the Registered Entity in a timely manner (normally sixty (60) days in advance) of changes or revisions to scheduled Compliance Audit dates.

3.1.3 Frequency of Compliance Audits

The Compliance Enforcement Authority will perform comprehensive Compliance Audits as required by the NERC Rules of Procedure and based on criteria established by NERC. In addition to scheduled Compliance Audits, the Compliance Enforcement Authority (i) may initiate an unscheduled Compliance Audit of any Registered Entity at any time if the Compliance Enforcement Authority reasonably determines it to be necessary to ensure the Registered Entity's compliance with Reliability Standards, and (ii) shall initiate an unscheduled Compliance Audit if directed by FERC. The Compliance Enforcement Authority shall notify NERC and FERC prior to or on the same date it notifies the Registered Entity that an unscheduled Compliance Audit is being initiated. If NERC initiates the unscheduled Compliance Audit, it shall notify the appropriate Regional Entity or Entities. The Compliance Enforcement Authority shall provide at least ten (10) business days advance notice to the Registered Entity that an unscheduled Compliance Audit is being initiated, which notice shall include identification of the members of the Compliance Audit team.

3.1.4 Scope of Compliance Audits

3.1.4.1 Reliability Standards

A Compliance Audit shall include those Reliability Standards applicable to the Registered Entity that are ~~identified in the NERC Implementation Plan for the current year~~determined through the NERC approved risk-based processes described herein, and may include other Reliability Standards applicable to the Registered Entity whether or not they are identified in the Regional Entity's Regional Implementation Plan for the current year.

Regional Entities will tailor the final scope of any Compliance Audit based on the results of the Registered Entity's Inherent Risk Assessment and, if applicable, taking into consideration the results of an Internal Controls Evaluation. ~~a Registered Entity's inherent risk and on the evaluation, if applicable, of the Registered Entity's internal controls pertinent to the applicable Reliability Standards.~~ Except as otherwise required in the Rules of Procedure, the Compliance Enforcement Authority may use any process herein, in addition to, or in lieu of a Compliance Audit to monitor compliance with Reliability Standards.

3.1.4.2 Period Covered

The Registered Entity's data and information must show compliance with the Reliability Standards that are the subject of the Compliance Audit for the entire period covered by the Compliance Audit. The Compliance Enforcement Authority will indicate the beginning and End Date of the audit period in its notice of the Compliance Audit. The audit period begins the day after the End Date of the prior Compliance Audit by the Compliance Enforcement Authority (or the later of June 18, 2007 or the date the Registered Entity became subject to Reliability Standards if the Registered Entity has not previously been subject to a Compliance Audit). The audit period will not begin prior to the End Date of the previous Compliance Audit. The Compliance Enforcement Authority may modify the beginning date of the audit period for any given Reliability Standard Requirement based on an intervening compliance monitoring process. The End Date should be a specified date prior to the scheduled start of the Compliance Audit, such as the date of the notification issued to the Registered Entity pursuant to Section 3.1.1 or the date that is thirty (30) days following the date of the notification.

The Registered Entity will be expected to demonstrate compliance for the entire period described above. If a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard. However, in such cases, the Compliance Enforcement Authority will require the Registered Entity to demonstrate compliance through other means. In addition, if the Compliance Audit team discovers a potential noncompliance occurring subsequent to the End Date, the potential noncompliance will be subject to a Preliminary Screen pursuant to Section 3.8.

3.1.4.3 Review of Mitigating Activities

The Compliance Audit may include a review of any Mitigating Activities which the Registered Entity has not yet completed, for the purpose of determining whether the Registered Entity is making adequate progress towards completion of the Mitigating Activities.

3.1.5 Conduct of Compliance Audits

3.1.5.1 Composition of Compliance Audit Teams

The Compliance Audit team shall be comprised of members whom the Compliance Enforcement Authority has determined have the requisite knowledge, training and skills to conduct the Compliance Audit. The Compliance Audit team may include (i) contractors and industry subject matter experts, (ii) NERC staff members (which may include contractors to NERC), (iii) compliance staff members of other Regional Entities, and (iv) representatives of FERC and other Applicable Governmental Authorities so long as the Registered Entity is subject to the Applicable Governmental Authority's reliability jurisdiction. The Compliance Audit team leader shall be a staff member from the Compliance Enforcement Authority and is responsible for the conduct of the Compliance Audit and preparation of the Compliance Audit report.

3.1.5.2 Requirements for Compliance Audit Team Members

Each Compliance Audit team member must:

- Be free of conflicts of interests in accordance with the Compliance Enforcement Authority policies. Employees or contractors of the Registered Entity being audited shall not be allowed to participate as auditors in the Compliance Audit of the Registered Entity.

- Comply with the NERC Antitrust Compliance Guidelines and shall have either signed appropriate confidentiality agreements or acknowledgments that the confidentiality agreement signed by the Compliance Enforcement Authority is applicable.

- Successfully complete all NERC or NERC-approved Regional Entity auditor training applicable to the Compliance Audit.

- Prior to the Compliance Audit, the Compliance Enforcement Authority shall provide confirmation to the Registered Entity that all Compliance Audit team members have executed confidentiality agreements or acknowledgements.

3.1.5.3 Compliance Audit Observers and Other Attendees

In any Regional Entity Compliance Audit of a Registered Entity, in addition to the Compliance Audit team members, the following may participate as observers: (i) NERC Staff (which may include contractors to NERC); (ii) other members of the Regional Entity's Compliance Staff; (iii) with the permission of the Regional Entity, Compliance Staff members of other Regional Entities; and (iv) representatives of FERC and of other Applicable Governmental Authorities so long as the Registered Entity is subject to the Applicable Governmental Authority's reliability jurisdiction. Any members of NERC staff, Regional Entity Compliance Staff, or Compliance Staffs of other Regional Entities or representatives of FERC or other Applicable Governmental

Authorities who are not Compliance Audit team members identified pursuant to Section 3.1.1 are observers.

In addition, at the request of the Registered Entity being audited, the Regional Entity may allow attendance at the Compliance Audit by: (1) representatives of corporate affiliates of the Registered Entity being audited that are Registered Entities or that provide compliance services, support or oversight to the Registered Entity being audited, and (2) representatives of Registered Entities whose compliance activities are conducted by the Registered Entity being audited or by the same corporate entity that conducts the compliance activities of the Registered Entity being audited (e.g., representatives of other members of a Joint Registration Organization or of participants in a Coordinated Functional Registration pursuant to Section 500 of the Rules of Procedure). Each such additional attendee must execute a confidentiality agreement approved by the Regional Entity.

Compliance Audit observers and attendees are not Compliance Audit team members and do not participate in conducting the Compliance Audit or in making Compliance Audit findings and determinations.

The Compliance Audit team leader or other staff of the Regional Entity conducting the Compliance Audit will communicate in advance with any observers or other attendees to ensure there are no undue disruptions to the Compliance Audit, such as space limitations, no conflicts of interest, and no other considerations that in the judgment of the Compliance Audit team leader may be detrimental to the conduct and quality of the Compliance Audit. If the Compliance Audit team leader identifies any such issues, he/she shall work with the proposed observers or attendees to facilitate observation in a less disruptive manner; or, alternatively, the Regional Entity Compliance staff will work with the proposed observers or attendees to schedule their participation in, observation of, or attendance at a different Compliance Audit in which such issues are not presented.

3.1.5.4 Registered Entity Objections to Compliance Audit Team

A Registered Entity subject to a Compliance Audit may object to any member of the Compliance Audit team on grounds of a conflict of interest or the existence of other circumstances that could interfere with the team member's impartial performance of his or her duties. Any such objections must be provided in writing to the Compliance Enforcement Authority no later than fifteen (15) days prior to the start of on-site Compliance Audit work. This fifteen (15) day requirement shall not apply where a Compliance Audit team member has been appointed less than twenty (20) days prior to the start of on-site Compliance Audit work, in which case the Registered Entity must provide any objections to the Compliance Enforcement Authority within five (5) business days after receiving notice of the appointment of the Compliance Audit team member.

In the case of an unscheduled Compliance Audit pursuant to Section 3.1.3, the Registered Entity must provide any objections to the Compliance Enforcement Authority at least five (5) business days prior to the start of on-site Compliance Audit work for the unscheduled Compliance Audit.

The Compliance Enforcement Authority will make a final determination on whether the member will participate in the Compliance Audit of the Registered Entity. Nothing in Section 3.1 shall be read to limit the participation of NERC staff in the Compliance Audit or to limit the participation of FERC staff in a Compliance Audit of a Registered Entity, or involving a portion of the Bulk Power System, over which FERC has jurisdiction.

3.1.6 Compliance Audit Reports

The Compliance Audit team shall develop a draft Compliance Audit report that shall include a description of the objective, scope, and methodology of the Compliance Audit; identify any evidence of potential noncompliance with Reliability Standards by the Registered Entity found by the Compliance Audit team; identify any Remedial Action Directives, Mitigation Plans or other Mitigating Activities which have been completed or pending in the year of the Compliance Audit; and identify if any Confidential Information has been redacted. The report may also state areas of concern and recommendations identified by the Compliance Audit team. The draft report will be provided to the Registered Entity for comment.

The Compliance Audit team considers corrections based on comments of the Registered Entity, finalizes the Compliance Audit report, and provides the Registered Entity with a copy of the final report on or before the date the final report is provided to NERC. The Compliance Enforcement Authority provides the final report to NERC, which in turn provides the report to FERC if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which FERC has jurisdiction and/or to another Applicable Governmental Authority if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which the other Applicable Governmental Authority has jurisdiction. The provision of the final Compliance Audit report to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure. Work papers and other documentation associated with the Compliance Audit shall be maintained by the Compliance Enforcement Authority in accordance with NERC or Regional Entity requirements.

NERC will not publicly post the final Compliance Audit report for at least five (5) business days following receipt. If the Compliance Audit report identifies any Possible Violations of one or more Reliability Standards, the final Compliance Audit report, or pertinent part thereof identifying the Possible Violations, shall not be released to the public by NERC until (i) the Possible Violation is dismissed prior to becoming a Confirmed Violation, or (ii) NERC submits a Notice of Penalty to FERC or other Applicable Governmental Authority, or (iii) the Registered Entity executes a settlement agreement with the Compliance Enforcement Authority pursuant to Section 5.6.

Information deemed by a Compliance Enforcement Authority or the Registered Entity as Critical Energy Infrastructure Information or Confidential Information shall be redacted from any public reports.

3.2 Self-Certifications

The Compliance Enforcement Authority may require Registered Entities to self-certify their compliance with Reliability Standards.

3.2.1 Self-Certification Process Steps

The process steps for the Self-Certification process are as follows:

- The Compliance Enforcement Authority posts and updates the reporting schedule containing the applicable reporting periods and informs Registered Entities. The Compliance Enforcement Authority and NERC will ensure that the appropriate Reliability Standards, compliance procedures, and required submittal forms for the Reliability Standards being evaluated are maintained and available.

- The Compliance Enforcement Authority requests the Registered Entity to make a Self-Certification within the advance notice period specified by the Reliability Standard. If the Reliability Standard does not specify the advance notice period, this request will be issued in a timely manner (normally thirty (30) days advance notice).

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the form and manner, and by the Required Date, specified by the Compliance Enforcement Authority. The Self-Certification response may state that (i) the Registered Entity is in compliance with the Reliability Standard Requirement, (ii) the Registered Entity is not in compliance with the Reliability Standard Requirement, (iii) the Registered Entity does not own Facilities that are subject to the Reliability Standard Requirement, or (iv) the Reliability Standard requirement is not applicable to the Registered Entity.

- At a minimum, the Compliance Enforcement Authority reviews Self-Certifications of non-compliance and Self-Certifications in which the Registered Entity has responded that it does not own Facilities that are subject to the Reliability Standard Requirement or that the Reliability Standard Requirement is not applicable to the Registered Entity and the Compliance Enforcement Authority may request additional data and/or information if necessary.

- If the Compliance Enforcement Authority's review of the Self-Certification indicates a potential noncompliance with a Reliability Standard by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

Receipt of a Self-Certification by the Compliance Enforcement Authority shall not be construed as a finding by the Compliance Enforcement Authority that the Registered Entity is compliant with, not compliant with, subject to, or not subject to, the Reliability Standard Requirement.

3.3 Spot Checks

Spot Checks will be conducted by the Compliance Enforcement Authority. Spot Checks may be initiated at the discretion of the Compliance Enforcement Authority or as directed by NERC at any time to verify or confirm Self-Certifications, Self-Reports, and Periodic Data Submittals. Spot Checks may also be random or may be initiated in response to events, as described in the Reliability Standards, or to operating problems, or system events.

3.3.1 Spot Check Process Steps

The process steps for Spot Checking are as follows:

- The Compliance Enforcement Authority shall issue a notification letter to the Registered Entity that a Spot Check will be performed, the reason for the Spot Check, and the scope of the Spot Check including the Reliability Standard Requirements that will be covered, in accordance with the advance notice period specified by the Reliability Standard. If the Reliability Standard Requirement does not specify an advance notice period, any information submittal request made by the Compliance Enforcement Authority will allow at least twenty (20) days for the Registered Entity to submit the information or make it available for review.

- The Compliance Enforcement Authority, as part of the notification package, shall provide the Registered Entity with the names and employment histories of the persons who will be conducting the Spot Check. The Compliance Enforcement Authority shall provide confirmation to the Registered Entity that the members of the Spot Check team have executed confidentiality agreements or acknowledgements. The Registered Entity may object to inclusion of any individual on the Spot Check team on the grounds specified in Section 3.1.5.4. Any such objections must be submitted to the Compliance Enforcement Authority by the later of (i) five (5) business days before the information being requested by the Compliance Enforcement Authority is submitted and (ii) five (5) business days after the Registered Entity is notified of the persons on the Spot Check team. Nothing in Section 3.1 shall be read to limit the participation of NERC staff in a Spot Check or to limit the participation of FERC staff in a Spot Check of a Registered Entity, or involving a portion of the Bulk Power System, over which FERC has jurisdiction.

- The Spot Check may require submission of data, documentation, and information and an on-site review.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date specified in the request.

- The Spot Check Team conducts a review of the information submitted to determine compliance with the Reliability Standards Requirements and may request additional data and/or information if necessary.

- If the Spot Check team's review of the information submitted indicates a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen pursuant to Section 3.8.

- The Spot Check team prepares a draft Spot Check report and provides the Registered Entity ten (10) business days to comment on the draft report.

- The Spot Check team considers any corrections based on the Registered Entity's comments, finalizes the Spot Check report and provides it to the Registered Entity and to NERC.

- If the Compliance Enforcement Authority is a Regional Entity, the Regional Entity provides the final report to NERC. NERC provides the report to FERC if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which FERC has jurisdiction and/or to another Applicable Governmental Authority if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which the other Applicable Governmental Authority has jurisdiction. The provision of the report to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure.

- The report will not be publicly posted, or otherwise made publicly available, by the Regional Entity or by NERC.

3.4 Compliance Investigations

A Compliance Investigation may be initiated at any time by the Compliance Enforcement Authority or NERC in response to a system disturbance, Complaint, or any potential noncompliance with a Reliability Standard identified by any other means.

Compliance Investigations will generally be led by the Regional Entity's staff. NERC reserves the right to assume the leadership of a Compliance Investigation.[1] The Regional Entity shall not be entitled to appeal NERC's decision to lead a Compliance Investigation.

Compliance Investigations are confidential, unless FERC directs that a Compliance Investigation should be public or that certain information obtained in the Compliance Investigation should be publicly disclosed. Confirmed Violations resulting from a Compliance Investigation will be made public.

FERC or another Applicable Governmental Authority may initiate an investigation at any time in response to a system disturbance, Complaint, or potential noncompliance with a Reliability Standard identified by any other means, or for any other purpose authorized by law. Investigations initiated by FERC or another Applicable Governmental Authority shall be governed by and conducted pursuant to the statutory authority and rules of the Applicable Governmental Authority and not the procedures set forth herein. If an Applicable Governmental Authority other than FERC initiates an investigation of a U.S.-related matter, NERC shall provide notice to FERC of the investigation prior to disclosure of any non-public U.S.-related compliance information regarding the matter to be investigated to the other Applicable Governmental Authority. NERC's notice to FERC shall identify the other Applicable Governmental Authority, shall describe the nature of the proposed disclosures to the other Applicable Governmental Authority, and shall state the procedures NERC will utilize in

[1]Examples of situations in which NERC may decide to lead a Compliance Investigation include: (i) to assure consistency in investigative processes, (ii) to coordinate Compliance Investigations into matters that may cross Regional Entity boundaries, (iii) where the potential noncompliance is related to the Regional Entity or one of its affiliates, divisions, committees or subordinate structures, or (iv) where the Regional Entity determines it cannot conduct the Compliance Investigation.

connection with the Compliance Investigation to ensure compliance with the requirements of 18 C.F.R. §39.7(b)(4) concerning nondisclosure of violations and Alleged Violations.

If FERC initiates an investigation of a non-U.S.-related matter, NERC shall provide notice of the investigation to the Applicable Governmental Authority having jurisdiction over the Registered Entity or the portion of the Bulk Power System that is the subject of the investigation prior to disclosure to FERC of any non-public non-U.S.-related compliance information regarding the matter to be investigated. NERC's notice to the other Applicable Governmental Authority shall describe the nature of the proposed disclosures to FERC and shall state the procedures NERC will utilize in connection with the investigation to ensure compliance with regulations of the other Applicable Governmental Authority or other law of the applicable jurisdiction concerning disclosure of non-public compliance information.

3.4.1 Compliance Investigation Process Steps

The process steps for a Compliance Investigation are as follows:

- The Compliance Enforcement Authority becomes aware of circumstances indicating a Reliability Standard may have been or is being violated and determines whether a Compliance Investigation is warranted. Within three (3) business days of the decision to initiate a Compliance Investigation, the Compliance Enforcement Authority: (i) notifies the Registered Entity of the initiation and initial scope of the Compliance Investigation, (ii) instructs the Registered Entity to preserve all records and information relevant to the Compliance Investigation, and (iii) provides a copy of the notice to NERC. The Compliance Investigation may be expanded beyond the initial scope based on information obtained by the Compliance Enforcement Authority after initiation of the Compliance Investigation.

- NERC assigns a NERC staff member to the Compliance Investigation as an observer or team member and to serve as a single point of contact for communications with NERC, and notifies the Registered Entity as to whether the NERC staff member is acting as an observer or as a team member. Within three (3) business days after NERC receives notice of the decision to initiate a Compliance Investigation, NERC will notify FERC and each other Applicable Governmental Authority having jurisdiction over a Registered Entity or a portion of the Bulk Power System to which the Compliance Investigation relates. Any such notice to FERC or to another Applicable Governmental Authority will be provided in accordance with Section 8.0, Reporting and Disclosure.

  The Compliance Enforcement Authority requests data or documentation and provides a list of individuals on the Compliance Investigation team and their recent employment history. Within ten (10) business days of receiving the notification of a Compliance Investigation, a Registered Entity subject to a Compliance Investigation may object to any individual member of the Compliance Investigation team on grounds of a conflict of interest or the existence of other circumstances that could interfere with the team member's impartial performance of his or her duties; however, the Registered Entity may not object to participation by NERC, by FERC staff or by staff of another Applicable Governmental Authority having reliability jurisdiction over the Registered Entity in the Compliance Investigation. Such objections must be provided in writing to

the Compliance Enforcement Authority within such ten (10) business day period. The Compliance Enforcement Authority will make a final determination as to whether the individual will participate in the Compliance Investigation of the Registered Entity.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date as specified in the request. If information is not received in the time and format requested, the Compliance Enforcement Authority may initiate the steps in **Process for Non-Submittal of Requested Data in Attachment 1.**

- If necessary, the Compliance Investigation may include an on-site visit with interviews of the appropriate personnel and review of data.

- The Compliance Enforcement Authority may require the Registered Entity to (i) provide a verification under oath by an officer, employee, attorney or other authorized representative of the Registered Entity attesting to the accuracy, completeness and truth of the Registered Entity's responses to the Compliance Enforcement Authority's requests for information; and (ii) produce one or more officers, employees or other authorized representatives of the Registered Entity who are familiar with the matter(s) that are the subject of the Compliance Investigation, to be interviewed or to provide testimony under oath concerning such matters. The Compliance Enforcement Authority shall determine in each case (i) whether representatives of the Registered Entity shall be allowed to be present when an interview is taking place or testimony is being taken, and (ii) whether, and by what method, the interview or testimony shall be recorded; provided, that counsel for the person being interviewed or giving testimony may be present when the interview is being conducted or testimony is being taken (regardless of whether such counsel also represents the Registered Entity).

- The Compliance Enforcement Authority reviews information to determine compliance with the Reliability Standards. The Compliance Enforcement Authority may request additional data and/or information, if necessary.

- The Compliance Enforcement Authority completes the assessment of compliance with the Reliability Standard, which may include review of a Mitigation Plan or Mitigating Activities, and provides a report of the Compliance Investigation to NERC and the Registered Entity.

- If the Compliance Enforcement Authority, at any time during the Compliance Investigation, identifies a potential noncompliance with a Reliability Standard Requirement by a Registered Entity, the Compliance Enforcement Authority shall conduct a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

- If the Compliance Enforcement Authority determines that no violation occurred, it shall send the Registered Entity and NERC a notice that the Compliance Investigation has been completed. NERC will in turn notify FERC and, if the Compliance Investigation pertained to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, will also notify such other

Applicable Governmental Authority. Any such notice to FERC or to another Applicable Governmental Authority shall be provided in accordance with Section 8.0, Reporting and Disclosure.

3.5 Self-Reports

Self-Reports are encouraged at the time a Registered Entity becomes aware (i) that it has, or may have, violated a Reliability Standard, or (ii) the Violation Severity Level of a previously reported violation has changed. Self-Reports of a violation of a Reliability Standard are encouraged regardless of whether the Reliability Standard requires reporting on a pre-defined schedule in the Compliance Program or whether the violation is determined outside the pre-defined reporting schedule. If possible, and without delaying the Self-Report, a Self-Report may include the actions that have been taken or will be taken to resolve the violation.

3.5.1 Self-Report Process Steps

The process steps for Self-Reports are as follows:

- The Compliance Enforcement Authority posts the Self-Report submittal forms and ensures they are maintained and available.
- The Registered Entity provides the Self-Report information to the Compliance Enforcement Authority.
- The Compliance Enforcement Authority reviews the information to evaluate compliance with the Reliability Standards and may request that the Registered Entity provide clarification or additional data and/or information.
- The Compliance Enforcement Authority conducts a Preliminary Screen of the Self-Report information in accordance with Section 3.8.

3.5A Self-Logging

Registered Entities found by the Compliance Enforcement Authority to be eligible, after a formal review of internal controls, pursuant to procedures adopted by NERC and the Regional Entities and provided to Applicable Governmental Authorities, may be granted approval by the Compliance Enforcement Authority to log noncompliance for subsequent review in lieu of submitting a Self-Report. The log shall be limited to noncompliance posing a minimal risk to the reliability of the Bulk Power System unless otherwise authorized by an Applicable Governmental Authority. Approved Registered Entities shall maintain a log with a detailed description of the noncompliance, the risk assessment, and the mitigating activities completed or to be completed. There is a rebuttable presumption that noncompliance logged in this manner will be resolved as a Compliance Exception. The Compliance Enforcement Authority will periodically review the logs and will make the logs available for review, upon request, by NERC and Applicable Governmental Authorities.

3.6 Periodic Data Submittals

The Compliance Enforcement Authority requires Periodic Data Submittals in accordance with the schedule stated in the applicable Reliability Standard, or as established by the Compliance Enforcement Authority, or on an as-needed basis. The Compliance Enforcement Authority shall issue requests for Periodic Data Submittals to Registered Entities within at least the minimum advance notice period specified by the applicable Reliability Standard. If the Reliability Standard does not specify an advance notice period, the Compliance Enforcement Authority will normally issue this request with no less than twenty (20) days advance notice.

3.6.1 Periodic Data Submittals Process Steps

The process steps for Periodic Data Submittal are as follows:

- The Compliance Enforcement Authority posts the current data reporting schedule on its website and informs Registered Entities of changes and/or updates. The Compliance Enforcement Authority ensures that the required submittal forms for the Reliability Standards being evaluated are maintained and available.

- The Compliance Enforcement Authority makes a request for a Periodic Data Submittal.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date specified in the request.

- The Compliance Enforcement Authority reviews the data submittal to determine compliance with the Reliability Standards and may request additional data and/or information if necessary.

- If the Compliance Enforcement Authority's review of the data submittal indicates a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority performs a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

Receipt of a Periodic Data Submittal by the Compliance Enforcement Authority shall not be construed as a finding by the Compliance Enforcement Authority that the Registered Entity is compliant with, not compliant with, subject to, or not subject to, the Reliability Standard Requirement.

3.7 Complaints

Either NERC or Regional Entities may receive Complaints alleging violations of a Reliability Standard. The Compliance Enforcement Authority will conduct a review of each Complaint it receives to determine if the Complaint provides sufficient basis for initiating another compliance monitoring or enforcement process, except that NERC will review any Complaint where the Compliance Enforcement Authority determines it cannot conduct the review, or if the complainant wishes to remain anonymous or specifically requests NERC to conduct the review of the Complaint.

If the Complaint is submitted to NERC, NERC will forward the information to the Regional Entity, as appropriate.

All anonymous Complaints will be reviewed and any resulting compliance monitoring or enforcement processes conducted by NERC will be conducted in accordance with Section 3.7.2 to prevent disclosure of the identity of the complainant.

The Compliance Enforcement Authority conducting the review will determine if the Complaint may be closed as a result of the initial review and assessment or if it provides sufficient basis for initiating another compliance monitoring or enforcement process. The Compliance Enforcement Authority will report the results of its review of the Complaint to NERC. If, as a result of the initial review of the Complaint, the Compliance Enforcement Authority determines that initiating another compliance monitoring or enforcement process is warranted, the Compliance Enforcement Authority shall conduct that compliance monitoring or enforcement process in accordance with the applicable provisions of Section 3.0.

3.7.1 Complaint Process Steps

The detailed process steps for the Complaint process are as follows:

- The complainant notifies NERC or a Regional Entity using the NERC compliance hotline, submitting a NERC Complaint reporting form, or by other means. NERC and the Regional Entity shall post a link to the Complaint reporting form on their respective websites. The Complaint should include sufficient information to enable NERC or the Regional Entity to make an assessment regarding whether the initiation of another compliance monitoring or enforcement process is warranted. NERC or the Regional Entity may not act on a Complaint if the Complaint is incomplete and does not include sufficient information.

- If the Compliance Enforcement Authority determines that initiation of another compliance monitoring or enforcement process is warranted, it initiates the compliance monitoring or enforcement process in accordance with the applicable provisions of Section 3.0 or Section 5.0; otherwise it takes no further action. The Compliance Enforcement Authority notifies the complainant, the Registered Entity, and NERC of the initiation of the compliance monitoring or enforcement process. If the Compliance Enforcement Authority determines that initiation of another compliance monitoring or enforcement process is not warranted, it will notify the complainant, NERC, and the Registered Entity that no further action will be taken.

- The Compliance Enforcement Authority fully documents the Complaint and the Complaint review, and whether another compliance monitoring or enforcement process is warranted.

3.7.2 Anonymous Complainant Notification Procedure

A complainant who believes, or has information indicating, there has been a violation of a Reliability Standard, and wishes to remain anonymous, can report the information and request

that the complainant's identity not be disclosed.[2] All Complaints lodged by a person or entity requesting that the complainant's identity not be disclosed shall be investigated by NERC following the procedural steps described in Section 3.7.1. Anonymous Complaints received by a Regional Entity will either be directed to NERC or the Regional Entity will collect and forward the information to NERC, at the Regional Entity's discretion. Neither NERC nor the Regional Entity shall disclose the identity of any person or entity reporting information indicating violations of Reliability Standards to NERC or to a Regional Entity that requests that his/her/its identity not be revealed. The identity of the complainant will only be known by NERC and in the case where a Regional Entity collects the information, by NERC and the Regional Entity. If the Compliance Enforcement Authority determines that initiation of another compliance monitoring and enforcement process is not warranted, it will notify the complainant, NERC, and the Registered Entity that no further action will be taken.

3.8 Preliminary Screen

If the Compliance Enforcement Authority obtains information, through one of the compliance monitoring processes described in this Section 3.0 or by any other means, that indicates a potential noncompliance with a Reliability Standard Requirement, the Compliance Enforcement Authority shall conduct a Preliminary Screen of the potential noncompliance. The Preliminary Screen shall be conducted within five (5) business days after the Compliance Enforcement Authority identifies the potential noncompliance, except that (i) if the Compliance Enforcement Authority identifies the potential noncompliance during a Compliance Audit, the Preliminary Screen shall be conducted immediately following the exit briefing of the Registered Entity, and (ii) if the Compliance Enforcement Authority identifies the potential noncompliance during a Compliance Investigation, the Preliminary Screen shall be conducted immediately after the Registered Entity is first notified of the potential noncompliance identified by the Compliance Investigation.

A Preliminary Screen shall be limited to determining whether:

(1) the entity allegedly involved in the potential noncompliance is a Registered Entity;

(2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to the entity, has been approved by the Applicable Governmental Authority, and is in effect at the time of the potential noncompliance; and

(3) if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation that is currently being processed.

If the Preliminary Screen results in an affirmative determination with respect to the above criteria, a Possible Violation exists and the Compliance Enforcement Authority shall proceed in

[2]NERC has established a Compliance Hotline that may be used for the submission of Complaints by persons or entities that do not want his/her/its identity disclosed (see www.nerc.com for additional information).

accordance with Section 5.0, unless ~~an alternative enforcement~~the Compliance Exception ~~p~~Process is used in accordance with Section 3A.0.

The Compliance Enforcement authority shall maintain records of all Preliminary Screens.

3A.0 ENFORCEMENT DISCRETION

Not all instances of noncompliance with Reliability Standards require the same type of processing and documentation. Noncompliance that does not pose a serious or substantial risk to the reliability of the Bulk Power System may be resolved through streamlined processes, when appropriate, consistent with processes approved by NERC and Applicable Governmental Authorities.

Absolute adherence to the enforcement process set out in section 5.0 may not be the most appropriate, efficient, or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the Compliance Enforcement Authority, and the Registered Entity.

The Find, Fix, Track, and Report and the Compliance Exception processes are alternatives to the process outlined in section 5.0. ~~The Find, Fix, Track, and Report process may be used to address noncompliance posing a minimal or moderate risk to the reliability of the Bulk Power System.~~

3A.1 Compliance Exception Process

The Compliance Exception~~s~~ process may be used to address noncompliance posing a minimal risk to the reliability of the Bulk Power System, unless an Applicable Governmental Authority authorizes expansion of the program. Compliance Exceptions are not included in a Registered Entity's compliance history for penalty purposes. However, a Compliance Enforcement Authority must (a) consider a history of C~~c~~ompliance E~~e~~xceptions where the failure to fully remediate the underlying compliance matter contributes to a subsequent serious or substantial noncompliance and (b) assess subsequent noncompliance to determine whether a Registered Entity should continue to qualify for Compliance Exception treatment.

The Compliance Exception process requires that:

(1) The Registered Entity mitigates the noncompliance; and

(2) The facts and circumstances of the noncompliance, including those associated with the determination of the level of risk and the related mitigation, are available for review by NERC and Applicable Governmental Authorities; and

(3) The noncompliance is tracked and analyzed as necessary and appropriate to identify emerging risks and other pertinent trends; and

(4) The Registered Entity is provided the opportunity to object to the use of the ~~alternative approach~~Compliance Exception Process to resolution of the noncompliance.

Changes to the processes and principles articulated in this section must be approved by Applicable Governmental Authorities.

~~**3A.2 Find, Fix, Track and Report Process**~~

~~The Find, Fix, Track and Report process may be used to address noncompliance posing a minimal or moderate risk to the reliability of the Bulk Power System.~~

~~The Find, Fix, Track, and Report process and the Compliance Exception process requires that:~~

- ~~The Registered Entity mitigates the noncompliance; and~~
- ~~The facts and circumstances of the noncompliance, including those associated with the determination of the level of risk and the related mitigation, are available for review by NERC and Applicable Governmental Authorities; and~~
- ~~The noncompliance is tracked and analyzed as necessary and appropriate to identify emerging risks and other pertinent trends; and~~
- ~~The Registered Entity is provided the opportunity to object to the use of the alternative approach to resolution of the noncompliance.~~

~~Changes to the processes and principles articulated in this section must be approved by Applicable Governmental Authorities.~~

4.0 ANNUAL IMPLEMENTATION PLANS

4.1 NERC Compliance Monitoring and Enforcement Program Implementation Plan

NERC will maintain and update the NERC Implementation Plan, to be carried out by Compliance Enforcement Authorities in the performance of their responsibilities and duties in implementing the NERC Compliance Monitoring and Enforcement Program. The NERC Implementation Plan will be provided to the Regional Entities on or about September 1 of each year and will ~~specify~~ identify risk elements related to the Reliability Standards ~~requiring reporting by Registered Entities~~to be considered for compliance oversight ~~to~~ by the Compliance Enforcement Authority ~~to provide verification of compliance through one of the monitoring methods described in this Compliance Program~~. The NERC Implementation Plan will be posted on the NERC website. NERC may update and revise the NERC Implementation Plan during the course of the year as necessary. Regional Entities have discretion to make modifications to the NERC Implementation Plan with respect to individual Registered Entities.

4.2 Regional Implementation Plan

By on or about October 1 of each year, each Regional Entity will submit a Regional Implementation Plan for the following calendar year to NERC for review and approval. The Regional Implementation Plan and the Regional Entity's other relevant Compliance Program documents shall be posted on the Regional Entity's website. The Regional Entity may update

and revise the Regional Entity Implementation Plan during the course of the year as necessary, with NERC approval, or as required by NERC. Regional Entities have discretion to make modifications to the Regional Entity Implementation Plan with respect to individual Registered Entities.

5.0 ENFORCEMENT ACTIONS

The Compliance Enforcement Authority shall determine (i) whether there have been violations of Reliability Standards by Registered Entities within the Compliance Enforcement Authority's Area of Responsibility, and (ii) if so, the appropriate Mitigating Activities, and Penalties and sanctions, as prescribed in the NERC *Sanction Guidelines* (Appendix 4B to the NERC Rules of Procedure). NERC will work to achieve consistency in the application of the *Sanction Guidelines* by Regional Entities by direct oversight and review of Penalties and sanctions, and each Regional Entity shall provide to NERC such information as is requested by NERC concerning any Penalty, sanction, or Mitigating Activities imposed by the Regional Entity.

The imposition and acceptance of Penalties and sanctions shall not be considered an acceptable alternative to any Registered Entity's continuing obligation to comply with the Reliability Standards.

The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies be made of Documents, data and information and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel. If Documents, data or information requested from a Registered Entity in connection with an enforcement process are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

The following enforcement process is undertaken by the Compliance Enforcement Authority following identification of a Possible Violation of a Reliability Standard Requirement by a Registered Entity. However, under the circumstances presented by some Possible Violations, Alleged Violations or Confirmed Violations, absolute adherence to the following enforcement process, to the exclusion of other approaches, may not be the most appropriate, efficient or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the Compliance Enforcement Authority and the Registered Entity. In such circumstances, other approaches may be considered and employed. The Registered Entity shall be entitled to object to the use of any such other approach.

5.1 Notice of Possible Violation

If a Preliminary Screen conducted in accordance with Section 3.8 results in an affirmative determination with respect to the Preliminary Screen criteria, a Possible Violation exists. Unless the Compliance Exception process in Section 3A.0 is used to address the Possible Violation, ~~T~~the Compliance Enforcement Authority shall issue a Notice of Possible Violation to the Registered Entity. The Notice of Possible Violation shall:

(i) state that a Possible Violation by the Registered Entity has been identified;

(ii) provide a brief description of the Possible Violation, including the Reliability Standard requirement(s) and, if known, the date(s) involved; and

(iii) instruct the Registered Entity to retain and preserve all data and records relating to the Possible Violation.

Upon issuing a Notice of Possible Violation, the Compliance Enforcement Authority reports the Possible Violation to NERC. NERC reports the Possible Violation to the Board of Trustees Compliance Committee and submits a Notice of Possible Violation, on a confidential basis, to FERC and to other Applicable Governmental Authorities, as applicable. Any such notice to FERC or to other Applicable Governmental Authorities shall be provided in accordance with Section 8.0, Reporting and Disclosure.

5.2 Assessment of Possible Violation

After issuing a Notice of Possible Violation, the Compliance Enforcement Authority shall conduct an assessment of the facts and circumstances surrounding the Possible Violation to determine whether evidence exists to indicate the Registered Entity has violated the Reliability Standard Requirement(s) identified in the Notice of Possible Violation, or whether the Possible Violation should be dismissed. The Compliance Enforcement Authority may consider any additional information to demonstrate that the Possible Violation should be dismissed or modified or resolved through the Find, Fix, Track and Report (FFT) process in section 5.2A.

5.2A FFT Process

The Find, Fix, Track and Report process may be used to address noncompliance posing a minimal or moderate risk to the reliability of the Bulk Power System.

The FFT process requires that:

(1) The Registered Entity mitigates the noncompliance; and

(2) The facts and circumstances of the noncompliance, including those associated with the determination of the level of risk and the related mitigation, are available for review by NERC and Applicable Governmental Authorities; and

(3) FFTs are tracked and analyzed as necessary by NERC as appropriate to identify emerging risks and other pertinent trends; and

(4) The Registered Entity is provided the opportunity to object to the use of the FFT process to resolution of the noncompliance.

5.3 Notification to Registered Entity of Alleged Violation

If the Compliance Enforcement Authority determines, based on an assessment of the facts and circumstances surrounding a Possible Violation, that evidence exists to indicate a Registered Entity has violated a Reliability Standard, the Compliance Enforcement Authority shall notify the Registered Entity of the determination of the Alleged Violation, through issuance of a Notice of Alleged Violation and Proposed Penalty or Sanction or similar notification, and shall report the Alleged Violation to NERC The notification of Alleged Violation shall be transmitted by the Compliance Enforcement Authority to the Registered Entity by electronic mail and shall be effective as of the date of the electronic mail message from the Compliance Enforcement Authority transmitting the notification. The notification of Alleged Violation shall include, at a minimum:

(i) the Reliability Standard and Requirement(s) thereof the Registered Entity has allegedly violated,

(ii) the date and time the Alleged Violation occurred (or is occurring),

(iii) the facts the Compliance Enforcement Authority believes demonstrate or constitute the Alleged Violation,

(iv) the proposed Penalty or sanction, if any, determined by the Compliance Enforcement Authority to be applicable to the Alleged Violation in accordance with the NERC *Sanction Guidelines*, including an explanation of the basis on which the particular Penalty or sanction was determined to be applicable,

(v) notice that the Registered Entity shall, within thirty (30) days, elect one of the following options or the Compliance Enforcement Authority will deem the Registered Entity to have accepted the determination of violation and proposed Penalty or sanction:

1. agree with the Alleged Violation and proposed Penalty or sanction, and agree to submit and implement a Mitigation Plan or other Mitigating Activities to correct the violation and its underlying causes, and may provide a response in accordance with Section 5.4, or

2. agree with the Alleged Violation and agree to submit and implement a Mitigation Plan or other Mitigating Activities to eliminate the violation and its underlying causes, but contest the proposed Penalty or sanction, and may provide a response in accordance with Section 5.4, or

3. contest both the Alleged Violation and proposed Penalty or sanction,

(vi) notice that the Registered Entity may elect to submit a Mitigation Plan while contesting the Alleged Violation and/or the proposed Penalty or sanction, and that submission of a Mitigation Plan will not waive the Registered Entity's right to contest the Alleged Violation and/or the proposed Penalty or sanction;

(vii) notice that if the Registered Entity elects to contest the Alleged Violation and/or the proposed Penalty or sanction, the Registered Entity may elect to have a hearing conducted pursuant to either (i) the short-form procedure in Section 1.3.4, or (ii) the general hearing procedure, in **Attachment 2, Hearing Procedures**, and

(viii) required procedures to submit the Registered Entity's Mitigation Plan.

NERC shall notify FERC of the Alleged Violation and, if the Alleged Violation pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, shall notify such other Applicable Governmental Authority of the Alleged Violation, within two (2) business days of receipt from the Compliance Enforcement Authority. Any such notice to FERC or to another Applicable Governmental Authority shall be provided in accordance with Section 8.0, Reporting and Disclosure.

5.4 Registered Entity Response

If the Registered Entity agrees with, does not contest, or does not respond to the notification of Alleged Violation within thirty (30) days following the date of the notification of Alleged Violation by electronic mail, it shall be deemed to have accepted the Compliance Enforcement Authority's determination of violation and Penalty or sanction, and the Compliance Enforcement Authority shall issue a Notice of Confirmed Violation or similar notification to the Registered Entity and shall report the Confirmed Violation to NERC. At the time of notifying the Registered Entity of the Confirmed Violation, the Compliance Enforcement Authority shall also provide notice to the Registered Entity that it may provide a written explanatory statement to accompany the filing with FERC and public posting of the Confirmed Violation. The Registered Entity's statement must include the name, title, and signature of an officer, employee, attorney or other authorized representative of the Registered Entity.

If the Registered Entity contests the Alleged Violation or the proposed Penalty or sanction, the Registered Entity shall submit to the Compliance Enforcement Authority, within thirty (30) days following the date of the notification of the Alleged Violation, a response explaining its position, signed by an officer, employee, attorney or other authorized representative together with any supporting information and documents. The Compliance Enforcement Authority shall schedule a conference with the Registered Entity within ten (10) business days after receipt of the response. If the Compliance Enforcement Authority and the Registered Entity are unable to resolve all issues within forty (40) days after the Registered Entity's response, the Registered Entity may request a hearing. The Compliance Enforcement Authority and the Registered Entity may agree in writing to extend the forty (40) day period. If no hearing request is made prior to the end of the forty (40) day period, the violation will be become a Confirmed Violation.

If a hearing is requested the Compliance Enforcement Authority shall initiate the hearing process in accordance with **Attachment 2, Hearing** Procedures.

5.5 Hearing Process for Compliance Hearings

The Compliance Enforcement Authority hearing process is set forth in **Attachment 2**.

5.6 Settlement Process

The Registered Entity can request settlement negotiations at any time, including prior to the issuance of notification of an Alleged Violation; however, the Compliance Enforcement Authority may decline to engage in or to continue settlement negotiations after a Possible Violation or Alleged Violation becomes a Confirmed Violation in accordance with Section 5.4. The Registered Entity or the Compliance Enforcement Authority may terminate settlement negotiations at any time. Where the Compliance Enforcement Authority has agreed top engage in settlement negotiations, the running of the time period specified in Section 5.4 for the Registered Entity to respond to the notification of Alleged Violation is suspended until settlement negotiations are concluded or terminate. NERC shall be notified of all settlement negotiations and may participate in any settlement negotiations. All settlement negotiations will be confidential until such time as the settlement is approved by NERC. For all settlement discussions, the Compliance Enforcement Authority shall require the Registered Entity to designate an individual(s) authorized to negotiate on its behalf.

The Compliance Enforcement Authority may consider all relevant facts in settlement negotiations. A settlement agreement must ensure that the reliability of the Bulk Power System will not be compromised by the settlement and that a violation of a Reliability Standard will not occur as a result of the settlement. All settlement agreements must provide, if the settlement is approved, for waiver of the Registered Entity's right to further hearings and appeal.

The Compliance Enforcement Authority and the Registered Entity will execute a settlement agreement setting forth the final settlement terms including all Penalties, sanctions and mitigation requirements provided for in the final settlement.

The Compliance Enforcement Authority shall report the terms of all settlements of compliance matters to NERC. NERC will review the settlement for the purpose of evaluating its consistency with other settlements entered into for similar violations or under other, similar circumstances. The Registered Entity may submit an explanatory statement, conforming to the requirements of Section 5.4, to be included in the settlement agreement and which shall be subject to consent of the Compliance Enforcement Authority as part of the settlement agreement. The settlement agreement may state that the Registered Entity (i) admits the Alleged Violation, or (ii) does not contest the Alleged Violation, or (iii) neither admits nor denies the Alleged Violation, but may not state that the Registered Entity denies the Alleged Violation. Based on this review, NERC will either approve the settlement or reject the settlement and notify the Compliance Enforcement Authority of any changes to the settlement that would result in approval, and within five (5) business days the Compliance Enforcement Authority will in turn notify the Registered Entity. If NERC rejects the settlement, the Compliance Enforcement Authority will attempt to negotiate a revised settlement agreement with the Registered Entity including any changes to the settlement specified by NERC.

NERC will report the approved settlement of the violation to FERC and, if the settlement relates to a Registered Entity or to a portion of the Bulk Power System over which another Applicable

Governmental Authority has jurisdiction, to such other Applicable Governmental Authority. Any such report shall be provided in accordance with Section 8.0, Reporting and Disclosure. NERC will also publicly post the violation settled (regardless of whether the settlement includes or does not include an admission of a violation) and the resulting Penalty or sanction provided for in the settlement. This posting shall include a copy of the settlement or a description of the terms of the settlement, and a copy of any Mitigation Plan that is agreed to as part of the settlement, with any Critical Energy Infrastructure Information and Confidential Information redacted. The Compliance Enforcement Authority will issue a letter setting forth the final settlement terms including all Penalties, sanctions and mitigation requirements provided for in the final settlement. Postings of Notices of Confirmed Violations are addressed in Section 8.0.

5.7 NERC Appeal Process

A Registered Entity or the Compliance Enforcement Authority may appeal the decision of a Regional Entity Hearing Body to NERC, as provided for in NERC Rules of Procedure, Section 409.

On appeal, NERC shall either affirm the decision or remand to the Compliance Enforcement Authority with reasons for its remand, which may include a direction to the Compliance Enforcement Authority to revise the decision. If NERC affirms the decision, the Compliance Enforcement Authority shall issue a Notice of Confirmed Violation to the Registered Entity. If NERC directs the Compliance Enforcement Authority to revise the decision, a Registered Entity that was the subject of the decision or the Compliance Enforcement Authority may reopen the proceeding on any issue whose resolution is affected by NERC's directive, irrespective of whether the issue was previously litigated, settled or unopposed.

5.8 Notification of Confirmed Violation

A Notice or other notification of Confirmed Violation issued to a Registered Entity pursuant to Sections 5.4 or 5.7 shall include a detailed record of the enforcement action, including the facts and circumstances analyzed and the information on which the Compliance Enforcement Authority relied in proposing a Penalty or sanction.

After NERC receives a notification of Confirmed Violation from the Compliance Enforcement Authority, NERC shall review the notification of Confirmed Violation and utilize the information therein to prepare a Notice of Penalty. NERC shall advise the Compliance Enforcement Authority of any additional detail or further development of the factual findings that NERC deems necessary before the Notice of Penalty can be issued.

NERC may direct the Compliance Enforcement Authority to revise a Penalty determination, in which case the Registered Entity subject to the Penalty, or the Compliance Enforcement Authority, as applicable, may reopen the proceedings on any issue on which the Penalty was based, irrespective of whether the issue was previously litigated, settled or unopposed.

5.9 Notice of Penalty

If (i) the Registered Entity accepts the Notice of Alleged Violation and Proposed Penalty or Sanction or other notification of enforcement action from the Compliance Enforcement

Authority, or (ii) a decision has been entered affirming an Alleged Violation and all appeals have been concluded, or (iii) a settlement agreement has been reached addressing the Possible Violation or Alleged Violation, NERC shall submit a Notice of Penalty to the Applicable Governmental Authority and provide a copy to the Compliance Enforcement Authority. The Compliance Enforcement Authority shall inform the Registered Entity that a Notice of Penalty is pending public filing, at least five (5) business days prior to the public filing and posting. NERC will file the Notice of Penalty with FERC and any other Applicable Governmental Authority no sooner than five (5) business days after NERC approves the Notice of Confirmed Violation or settlement agreement.

NERC shall file the Notice of Penalty with FERC and, if the Possible Violation or Alleged Violation pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority. Any such filing with FERC or with another Applicable Governmental Authority shall be made in accordance with Section 8.0, Reporting and Disclosure. NERC will include with the Notice of Penalty any statement provided by the Registered Entity as set forth in Sections 5.4 or 5.6.

The Penalty or sanction will be effective upon expiration of the thirty (30) day period following filing with FERC of the Notice of Penalty (or such longer period as ordered by FERC) or, if FERC decides to review the Penalty or sanction, upon final determination by FERC.

5.10 Completion of Enforcement Action

Following FERC approval of, or expiration of the period for action by FERC on, a Notice of Penalty filed by NERC, the Compliance Enforcement Authority shall issue a payment due notice and invoice to the Registered Entity. The payment due notice and invoice shall state the payment due date which shall be thirty (30) days from the date of the payment due notice and invoice. Upon payment of all monetary Penalties by the Registered Entity, the Compliance Enforcement Authority shall issue a notice confirming payment to the Registered Entity, and provide a copy of the notice confirming payment to NERC. Following the completion by the Registered Entity of all requirements set forth in the Notice of Penalty and any settlement agreement, the Compliance Enforcement Authority shall issue the Registered Entity a Notice of Completion of Enforcement Action.

If the Compliance Enforcement Authority dismisses or disposes of a Possible Violation or Alleged Violation that does not become a Confirmed Violation, the Compliance Enforcement Authority shall issue a Notice of Completion of Enforcement Action to the Registered Entity.

A copy of the Notice of Completion of Enforcement Action shall also be provided to NERC by the Compliance Enforcement Authority.

The Notice of Completion of Enforcement Action shall include a release of any data retention directives that were previously issued to the Registered Entity in connection with the matter. Upon issuance of a Notice of Completion of Enforcement Action, tracking of the violation is completed, and the enforcement action shall be closed.

5.11 Special Procedures for an Enforcement Action Against an ISO/RTO Where the Monetary Penalty May be Allocated by the ISO/RTO to Other Entities

A Registered Entity that is an ISO/RTO may have authority to allocate, pursuant to a proceeding under section 205 of the Federal Power Act, some or all of a monetary Penalty imposed on the ISO/RTO for violation of a Reliability Standard, to another entity(ies) that the Compliance Enforcement Authority, NERC or FERC determines was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation of the Reliability Standard. This section sets forth the procedures to be followed when an ISO/RTO that has received a Notice of Possible Violation requests a determination by the Compliance Enforcement Authority that another entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation.

The procedures in this section apply only where an ISO/RTO requests a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation (if confirmed) identified in a Notice of Possible Violation issued to the ISO/RTO, and shall not apply where the ISO/RTO anticipates or is entitled to allocate or assign a monetary Penalty among all, or an identified segment of, its members, customers or users, pursuant to general cost recovery provisions in the ISO/RTO's tariffs, agreements or governance documents and regardless of actual fault or responsibility of the entities to whom the monetary Penalty is issued for the violation.

5.11.1 ISO/RTO's Request for Determination and Notice to Other Entity(ies)

In order to request the Compliance Enforcement Authority to make a determination in an enforcement action that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to a violation (if confirmed) of a Reliability Standard for which the ISO/RTO has received a Notice of Possible Violation, the ISO/RTO shall, no later than ten (10) business days after receiving the Notice of Possible Violation or such additional period as the Compliance Enforcement Authority may permit for good cause shown (i) submit a written request to the Compliance Enforcement Authority and (ii) issue a notice to the specified other entity(ies), each conforming to the requirements of the following two paragraphs of this section.

The ISO/RTO's written request to the Compliance Enforcement Authority shall contain:

(1) the Compliance Enforcement Authority's identification number for the Notice of Possible Violation;

(2) a statement that the ISO/RTO is requesting that the Compliance Enforcement Authority make a determination that a specified other entity(ies) was responsible, in whole or in part, for actions and omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation;

(3) the name(s) of, and contact information for, the specified other entity(ies), including name(s) and address(es) of the entity(ies) and name(s), telephone number(s) and e-mail address(es) of the contact person(s) for the other entity(ies);

(4) a statement that the ISO/RTO has authority to allocate some or all of the monetary Penalty to the specified other entity(ies), including citations to any supporting tariffs, agreements, orders, or governance documents, and a brief explanation to show that the specified other entity(ies) are subject to the tariffs, agreements, orders and/or other governance documents; and

(5) a brief statement of the factual basis on which the ISO/RTO contends in good faith that the specified other entity(ies) was responsible for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation. As the enforcement action proceeds, the ISO/RTO may supplement, expand or modify this explanation as additional information becomes available during the course of the enforcement action.

The ISO/RTO's notice to the specified other entity(ies) shall contain the following information:

(1) The name of the specified other entity, and the name, telephone number and e-mail address of the specified other entity's contact person (person to whom the notice is being sent);

(2) A statement that the ISO/RTO has received a Notice of Possible Violation from the Compliance Enforcement Authority, the Compliance Enforcement Authority's identification number for the Notice of Possible Violation, and contact information for the Compliance Enforcement Authority;

(3) A statement that the ISO/RTO has requested the Compliance Enforcement Authority to determine that the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, and that the ISO/RTO intends to seek to allocate to the specified other entity all or a portion of any monetary Penalty that is imposed on the ISO/RTO for the violation (if confirmed), if the Compliance Enforcement Authority determines the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation.

(4) A statement that the specified other entity should promptly contact the Compliance Enforcement Authority for further information and to request to participate in the enforcement action relating to the Notice of Possible Violation.

The ISO/RTO shall cause its notice to the specified other entity(ies) to be delivered to the other entity(ies) by next-business-day delivery using a delivery service that provides verification of delivery. The ISO/RTO shall provide the Compliance Enforcement Authority with (i) a copy of the notice sent to each specified other entity, and (ii) a copy of the delivery service's verification of delivery of the notice to each specified other entity.

5.11.2 Responses of the Compliance Enforcement Authority and the Specified Other Entity(ies) to ISO/RTO's Request for Determination and Notice

If (i) the ISO/RTO's written request meets the requirements of Section 5.11.1, the Compliance Enforcement Authority shall provide the specified other entity(ies) with a copy of a non-disclosure agreement (which shall include the specified other entity's agreement to comply with the confidentiality requirements of the Compliance Program and of Section 1500 of the NERC Rules of Procedure) that must be executed to obtain a copy of the Notice of Possible Violation and a copy of the ISO/RTO's written request to the Compliance Enforcement Authority for a determination that the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation. In addition, the Compliance Enforcement Authority shall advise the specified other entity(ies) that: (i) the specified other entity(ies) may elect not to participate in the enforcement action, and may submit a written statement to the Compliance Enforcement Authority stating why the specified other entity is not participating and providing any facts or information the other entity wishes to provide concerning the occurrence(s) that are the subject of the Notice of Possible Violation, and (ii) whether or not the specified other entity elects to participate in the enforcement action, the Compliance Enforcement Authority may determine that the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation.

If the ISO/RTO's written request meets the requirements of Section 5.11.1, then the specified other entity(ies) shall be permitted to participate in the enforcement action concerning the Notice of Possible Violation if the other entity(ies) submits a written request to participate to the Compliance Enforcement Authority and executes a non-disclosure agreement in the form provided by the Compliance Enforcement Authority. The specified other entity must submit its written request to participate prior to, as applicable (i) the date of execution of a settlement agreement between the Compliance Enforcement Authority and the ISO/RTO, or (ii) the date that the Compliance Enforcement Authority issues a Notice of Confirmed Violation to the ISO/RTO. The Compliance Enforcement Authority is not required to suspend or delay the enforcement process pending receipt of a request to participate from the specified other entity(ies), nor to revisit or redo any aspect of the enforcement process that has already occurred prior to receipt of the specified other entity(ies)'s written request to participate; however, upon receipt of a written request to participate and executed nondisclosure agreement from the specified other entity(ies), the Compliance Enforcement Authority shall suspend activity in the enforcement action until it has acted on the request to participate.

Upon receiving the specified other entity's written request to participate in the enforcement action and the other entity's executed nondisclosure agreement, the Compliance Enforcement Authority shall issue a notice to the ISO/RTO and to the specified other entity stating that the specified other entity is allowed to participate in the enforcement action. The Compliance Enforcement Authority's notice that the specified other entity is allowed to participate in the enforcement action shall include a copy of the Notice of Possible Violation originally issued to the ISO/RTO and, if a Notice of Alleged Violation and Proposed Penalty or Sanction or similar notification has been issued to the ISO/RTO, a copy of the latter Notice or notification. Upon receiving notice from the Compliance Enforcement Authority that it is allowed to participate in the enforcement action, the specified other entity may participate in the same manner as the ISO/RTO and shall be subject to all applicable requirements and deadlines specified in the NERC Compliance Program.

If the ISO/RO fails to meet the requirements of Section 5.11.1, the Compliance Enforcement Authority shall issue a notice to the ISO/RTO and to the specified other entity(ies) stating that the Compliance Enforcement Authority will not make the determination requested by the ISO/RTO and therefore the specified other entity will not be allowed to participate in the enforcement action relating to the Notice of Possible Violation.

5.11.3 Compliance Enforcement Authority's Notices to NERC

(a) Within five (5) business days after receiving an ISO/RTO's written request for a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to a violation identified in the Notice of Possible Violation issued to the ISO/RTO, the Compliance Enforcement Authority shall provide to NERC (i) a copy of the ISO/RTO's written request for a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, and (ii) the ISO/RTO's notice to the specified other entity(ies).

(b) On the same day that the Compliance Enforcement Authority issues a notice pursuant to Section 5.11.2 stating, as applicable, that (i) it will or will not make the determination requested by the ISO/RTO or (ii) the specified other entity(ies) are or are not allowed to participate in the enforcement action, the Compliance Enforcement Authority shall provide a copy of the notice to NERC and shall send a copy of the notice to any other entities that have been allowed to participate in the enforcement action.

5.11.4 Compliance Enforcement Authority's Determination

After issuing a notice pursuant to Section 5.11.3 that it will make a determination as to whether the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation that is the subject of the Notice of Possible Violation issued to the ISO/RTO, then, if the enforcement action is not resolved by a settlement agreement stating whether or not the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, the Compliance Enforcement Authority shall make, and include in its proposed Notice of Penalty, its determination of whether or not the specified other entity(ies) were responsible, in whole or in part, for actions or omissions that caused or contributed to the violation. The Compliance Enforcement Authority's determination shall only address whether or not the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation, and shall not address whether all or a part of any monetary Penalty imposed on the ISO/RTO for the violation should be allocated or assigned to the specified other entity(ies).

The specified other entity(ies) shall be entitled to request a hearing on the Compliance Enforcement Authority's determination pursuant to Section 1.3.1 of Attachment 2 of this Appendix 4C, and to appeal the Hearing Body's decision pursuant to Section 1.7.10 of Attachment 2 to this Appendix 4C, as though the specified other entity(ies) were a Registered Entity(ies).

5.11.5 Procedure Where ISO/RTO Members Are Allowed to Directly Assign Monetary Penalties for Violations of Reliability Standards to the ISO/RTO

If an ISO/RTO's tariffs, agreement or other relevant governance documents establish procedures that allow members of the ISO/RTO to directly assign to the ISO/RTO monetary Penalties imposed on the ISO/RTO member(s) for violations of Reliability Standards, then the ISO/RTO members may follow the same requirements of Sections 5.11.1 and 511.2 as are applicable to an ISO/RTO under those sections, and the ISO/RTO shall be afforded the same rights to participate in the enforcement action as a specified other entity under Sections 5.11.1, 5.11.2, and 5.11.4, subject to the same requirements and conditions specified in those sections. In such circumstances, the ISO/RTO shall be deemed to be a "specified other entity" for purposes of this Section.

5.11.6 Obligation to Pay Monetary Penalty

(a) The ISO/RTO shall be obligated and responsible to pay any monetary Penalty imposed by the Compliance Enforcement Authority on the ISO/RTO for violation of a Reliability Standard, in accordance with Section 5.10, (i) regardless of whether the Compliance Enforcement Authority has made a determination that a specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation, (ii) without regard to the timing of any separate proceeding(s) in which the ISO/RTO seeks to allocate some or all of the monetary Penalty to a specified other entity(ies), and (iii) without regard to whether or when the ISO/RTO receives payment from the specified other entity(ies).

(b) In an enforcement action subject to Section 5.11.5, the ISO/RTO member(s) shall be obligated and responsible to pay any monetary Penalty imposed by the Compliance Enforcement Authority on the ISO/RTO member(s) for violation of a Reliability Standard, regardless of whether or when the ISO/RTO members receive payment or reimbursement from the ISO/RTO.

6.0 MITIGATION OF VIOLATIONS OF RELIABILITY STANDARDS

The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies be made of Documents, data and information and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel. If

Documents, data, information or other reports requested from a Registered Entity in connection with development of a Mitigation Plan or other Mitigating Activities are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

6.1 Requirement for Submission of Mitigation Plans

A Registered Entity found to be in violation of a Reliability Standard shall file with the Compliance Enforcement Authority (i) a proposed Mitigation Plan to correct the violation, or (ii) a description of how the violation has been mitigated, and any requests for extensions of Mitigation Plans or a report of completed mitigation. A Registered Entity may also submit a proposed Mitigation Plan at any other time, including with a Self-Report, or, without admitting it has committed a violation, in response to a Notice of Possible Violation or notification of Alleged Violation.

6.2 Contents of Mitigation Plans

A Mitigation Plan shall include the following information:

- The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section 2.0.

- The Possible, Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.

- The cause of the Possible, Alleged or Confirmed Violation(s).

- The Registered Entity's action plan to correct the Possible, Alleged or Confirmed Violation(s).

- The Registered Entity's action plan to correct the cause of the Possible, Alleged or Confirmed Violation.

- The Registered Entity's action plan to prevent recurrence of the Possible, Alleged or Confirmed Violation(s).

- The anticipated impact of the Mitigation Plan on the Bulk Power System reliability and an action plan to mitigate any increased risk to the reliability of the Bulk Power System while the Mitigation Plan is being implemented.

- A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Possible, Alleged or Confirmed Violation(s) corrected.

- Implementation milestones no more than three (3) months apart for Mitigation Plans with

expected completion dates more than three (3) months from the date of submission. Additional violations could be determined for not completing work associated with accepted milestones.

- Any other information deemed necessary or appropriate.

The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity.

6.3 Timetable for Completion of Mitigation Plans

The Mitigation Plan shall be completed in accordance with its terms. At the Compliance Enforcement Authority's discretion, the completion deadline may be extended for good cause including, but not limited to: (i) operational issues such as the inability to schedule an outage to complete Mitigating Activities, and (ii) construction requirements in the Mitigation Plan that require longer to complete than originally anticipated. If the Mitigation Plan extends beyond the next applicable reporting/assessment period, sanctions for any violation of the applicable Reliability Standard(s) occurring during the implementation period will be held in abeyance and will be waived if the Mitigation Plan is satisfactorily completed.

Any violations assessed during the period of time the accepted Mitigation Plan is being implemented will be recorded by the Compliance Enforcement Authority with associated sanctions or Penalties. Regional Entities will report any findings of violations recorded during this time period to NERC with the notation that the Registered Entity is working under an accepted Mitigation Plan with an extended completion date with Penalties and sanctions held in abeyance until completion of the Mitigation Plan. Upon completion of the accepted Mitigation Plan in accordance with Section 6.6, the Compliance Enforcement Authority will notify the Registered Entity that any findings of violations of the applicable Reliability Standard during the period that the accepted Mitigation Plan was being implemented have been waived and no Penalties or sanctions will apply. Regional Entities will also notify NERC of any such waivers of violations of Reliability Standards.

A request for an extension of any milestone or the completion date of the accepted Mitigation Plan by a Registered Entity must be received by the Compliance Enforcement Authority at least five (5) business days before the original milestone or completion date. The Compliance Enforcement Authority may accept a request for an extension or modification of a Mitigation Plan if the Compliance Enforcement Authority determines the request is justified, and shall notify NERC of the extension or modification within five (5) business days.

If a Mitigation Plan submitted by a Registered Entity is rejected by the Regional Entity acting as Compliance Enforcement Authority or the Hearing Body in accordance with Section 6.5, the Registered Entity shall be subject to any findings of violation of the applicable Reliability Standards during the period the Mitigation Plan was under consideration and to imposition of any Penalties or sanctions imposed for such violations.

6.4 Submission of Mitigation Plans

A Mitigation Plan may be submitted at any time but shall have been submitted by the Registered Entity within thirty (30) days after being served the notification of Alleged Violation, if the Registered Entity does not contest the Alleged Violation and Penalty or sanction, or shall be reflected in a settlement agreement or Notice of Penalty. If the Registered Entity disputes the Alleged Violation or the Penalty or sanction, the Registered Entity shall submit its Mitigation Plan within ten (10) business days following issuance of the written decision of the Hearing Body, unless the Registered Entity elects to appeal the Hearing Body's determination to NERC. The Registered Entity may choose to submit a Mitigation Plan while it contests an Alleged Violation or Penalty or sanction or in response to a Notice of Possible Violation; such submission shall not be deemed an admission of a violation or the appropriateness of a Penalty or sanction. If the Registered Entity has not yet submitted a Mitigation Plan, or the Registered Entity submits a Mitigation Plan but it is rejected by the Regional Entity acting as Compliance Enforcement Authority or the Hearing Body in accordance with Section 6.5, any subsequent violations of the Reliability Standard identified by the Compliance Enforcement Authority before the Hearing Body renders its decision will not be held in abeyance and will be considered as repeat violations of the Reliability Standard.

6.5 Review and Acceptance or Rejection of Proposed Mitigation Plans

Unless the time period is extended by the Compliance Enforcement Authority, it will complete its review of the Mitigation Plan, and will issue a written statement accepting or rejecting the Mitigation Plan, within thirty (30) days of receipt; otherwise the Mitigation Plan will be deemed accepted. In order to extend the initial or an extended period for review of the Mitigation Plan, the Compliance Enforcement Authority shall, within the initial or extended review period, notify the Registered Entity (and NERC if NERC is not the Compliance Enforcement Authority) that the review period is being extended and identify the date by which the Compliance Enforcement Authority will complete its review of the Mitigation Plan. The Compliance Enforcement Authority's extension notice shall also state that if the Compliance Enforcement Authority has not issued a notice by the end of the extended review period either stating that the Compliance Enforcement Authority accepts or rejects the proposed Mitigation Plan or further extending the Compliance Enforcement Authority's period for review of the Mitigation Plan, the Mitigation Plan will be deemed accepted.

If the Compliance Enforcement Authority rejects a Mitigation Plan, the Compliance Enforcement Authority will provide the Registered Entity with a written statement describing the reasons for the rejection, and will require the Registered Entity to submit a revised Mitigation Plan by the Required Date. The Compliance Enforcement Authority will notify the Registered Entity within ten (10) business days after receipt of a revised Mitigation Plan whether the Compliance Enforcement Authority will accept or reject the revised Mitigation Plan and provide a written statement describing the reasons for rejection and the Required Date for the second revised Mitigation Plan. If the second review results in rejection of the Mitigation Plan, the Registered Entity may request a hearing in accordance with the Hearing Procedures, by submitting to the Compliance Enforcement Authority a written request for hearing including an explanation of why the Mitigation Plan should be accepted. After the hearing is completed, the Compliance Enforcement Authority will issue a written statement accepting a Mitigation Plan it deems as appropriate.

Within five (5) business days after a Regional Entity accepts a Mitigation Plan, the Regional Entity (i) will notify NERC and the Registered Entity of the acceptance of the Mitigation Plan and (ii) will provide the accepted Mitigation Plan to NERC. NERC will review the accepted Mitigation Plan and, within thirty (30) days following its receipt of the Mitigation Plan from the Regional Entity, will notify the Regional Entity and the Registered Entity, on a contemporaneous basis, as to whether the Mitigation Plan is approved or disapproved by NERC. If NERC disapproves a Mitigation Plan that was accepted by the Regional Entity, NERC shall state its reasons for the rejection, and may state the changes to the Mitigation Plan that would result in approval by NERC. The Registered Entity shall not be subject to findings of violations of the specific Requirements of Reliability Standards that are the subject of the Mitigation Plan or to imposition of Penalties or sanctions for such violations with respect to the period of time the Mitigation Plan was under consideration by NERC and for a reasonable period following NERC's disapproval of the Mitigation Plan, so long as the Registered Entity promptly submits a modified Mitigation Plan that addresses the concerns identified by NERC.

If a Registered Entity submits a Mitigation Plan prior to issuance of a notification of Confirmed Violation or entry into a settlement, such as with a Self-Report or in response to a Notice of Possible Violation, the Regional Entity may provisionally accept the proposed Mitigation Plan. If the Regional Entity subsequently determines, upon completing its assessment of the Possible Violation, that the facts and circumstances are different than those on which the accepted Mitigation Plan was based, the Regional Entity may, by notice to the Registered Entity and to NERC, require the Registered Entity to submit a revised Mitigation Plan that fully addresses the facts and circumstances of the violation. The Regional Entity's notice shall state the additional or different facts and circumstances that need to be addressed in the revised Mitigation Plan. The Registered Entity shall submit a revised Mitigation Plan in response to the notice within thirty (30) days following the date of the notice, unless the Regional Entity specifies or allows a longer time period. The Registered Entity's revised Mitigation Plan shall be subject to review and acceptance or rejection by the Regional Entity and by NERC in accordance with this Section 6.5. If the Regional Entity issues a notification of Confirmed Violation or enters into a settlement with the Registered Entity and does not identify a need to request modifications to the provisionally-accepted Mitigation Plan based on additional or different facts and circumstances, the Regional Entity shall issue a notice to the Registered Entity, with a copy to NERC, stating that the "provisional" nature of the acceptance is terminated and the acceptance is final. The Regional Entity shall issue such notice within five (5) business days of issuance of the Notice of Confirmed Violation or entry into the settlement.

NERC will submit to FERC, as non-public information, an approved Mitigation Plan relating to violations of Reliability Standards within seven (7) business days after NERC approves the Mitigation Plan. NERC shall publicly post the approved Mitigation Plan as part of the public posting of the related Notice of Penalty in accordance with Section 8.0 or settlement in accordance with Section 5.6.

6.6 Completion/Confirmation of Implementation of Mitigation Plans

The Registered Entity shall provide updates at least quarterly to the Compliance Enforcement Authority on the progress of the Mitigation Plan. The Compliance Enforcement Authority will track the Mitigation Plan to completion and may conduct on-site visits and review status during Compliance Audit to monitor Mitigation Plan implementation.

Upon completion of the Mitigation Plan, the Registered Entity shall provide to the Compliance Enforcement Authority certification, signed by an officer, employee, attorney or other authorized representative of the Registered Entity, that all required actions described in the Mitigation Plan have been completed and shall include data or information sufficient for the Compliance Enforcement Authority to verify completion. The Compliance Enforcement Authority shall request such data or information and conduct follow-up assessments, on-site or other Spot Checks, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed.

In the event all required actions in the Mitigation Plan are not completed within the applicable deadline including any extensions of the original deadline granted under Section 6.3, any violation(s) of a Reliability Standard subject to the Mitigation Plan that occurred during the originally scheduled time period for completion will be enforced immediately and a new Mitigation Plan must be submitted for acceptance by the Compliance Enforcement Authority. In addition, the Compliance Enforcement Authority may conduct a Compliance Audit of, or issue a Remedial Action Directive to, the Registered Entity.

Upon request by NERC, the Regional Entity will provide to NERC the quarterly status reports and such other information as NERC requests. The Regional Entity will notify NERC when each Mitigation Plan is verified to have been completed.

6.7 Recordkeeping

The Compliance Enforcement Authority will maintain a record containing the following information for each Mitigation Plan:

- Name of Registered Entity.
- The date of the violation.
- Monitoring method by which the violation was detected, i.e., Self-Certification, Self-Report, Compliance Audit, Compliance Investigation, Complaint, etc.
- Date(s) of Notice of Possible Violation and notification of Alleged Violation (if applicable).
- Expected and actual completion date of the Mitigation Plan and major milestones.
- Expected and actual completion date for each required action.
- Accepted changes to milestones, completion dates, or scope of Mitigation Plan.
- Registered Entity's completion notice and data submitted as evidence of completion.

7.0 REMEDIAL ACTION DIRECTIVES

The Compliance Enforcement Authority may issue a Remedial Action Directive when such action is immediately necessary to protect the reliability of the Bulk Power System from an

imminent or actual threat. A Remedial Action Directive may include, but is not limited to, any of the following: specifying operating or planning criteria, limits, or limitations; requiring specific system studies; defining operating practices or guidelines; requiring confirmation of data, practices, or procedures through inspection testing or other methods; requiring specific training for personnel; requiring development of specific operating plans; directing a Registered Entity to develop and comply with a plan to remediate a violation; imposing increased auditing or additional training requirements; and requiring a Registered Entity to cease an activity that may constitute a violation of a Reliability Standard.

A Remedial Action Directive may be issued to a Registered Entity at any time, including during any procedures relating to a Possible Violation or an Alleged Violation of a Reliability Standard. The Compliance Enforcement Authority will specify whether a Remedial Action Directive obviates the need for a Mitigation Plan.

Prior to issuing a Remedial Action Directive, the Compliance Enforcement Authority shall consult the Reliability Coordinator for the Registered Entity.

Any Remedial Action Directive must be provided in a notice to the Registered Entity and shall include: (i) a list of the Possible Violation(s) or Alleged Violation(s) of Reliability Standards that are the basis for issuance of the Remedial Action Directive; (ii) a discussion of the factual basis for the Remedial Action Directive; (iii) the requirements the Compliance Enforcement Authority is imposing to remove the imminent or actual threat to the reliability of the Bulk Power System; (iv) a deadline for compliance and a schedule for specific periodic updates to the Compliance Enforcement Authority; and (v) notice to the Registered Entity that failure to comply with the directive by the Required Date may result in further Remedial Action Directives or significantly increased sanctions.

The Compliance Enforcement Authority will cause the notice of the Remedial Action Directive to be delivered to the Registered Entity by (i) electronic mail to the Registered Entity's CEO or equivalent and copied to the Registered Entity's designated contact person for reliability matters and (ii) by a recognized express courier service that provides tracking and verification of delivery to the recipient. The notice will be deemed received on the earlier of the actual date of receipt of the electronic submission or receipt of the express courier delivery as specified by the express courier service's verification of delivery. The Compliance Enforcement Authority will monitor implementation of Remedial Action Directives as necessary to verify compliance.

The Compliance Enforcement Authority will notify NERC within two (2) business days after issuing a Remedial Action Directive and will copy NERC on all correspondence sent to the Registered Entity.

Once the Compliance Enforcement Authority has given the Registered Entity notice of the Remedial Action Directive, the Registered Entity may contest the Remedial Action Directive by giving written notice to the Compliance Enforcement Authority within two (2) business days following the date of actual receipt of notice of the Remedial Action Directive. Due to the urgency of resolving any objections to a Remedial Action Directive, the hearing shall be conducted under the expedited hearing process set forth in Section 1.9 of **Attachment 2, Hearing Procedures**. Notice to contest the Remedial Action Directive and participation in the hearing process set forth in Section 1.9 of **Attachment 2, Hearing Procedures** shall constitute

the Registered Entity's right to appeal the Remedial Action Directive. The Registered Entity may elect not to implement the Remedial Action Directive until the hearing process is completed, or may proceed with implementing the Remedial Action Directive even if it is contesting the Remedial Action Directive.

8.0 REPORTING AND DISCLOSURE

8.1 Information to be Reported

Regional Entities shall promptly submit to NERC electronic reports containing current information concerning the information listed below. NERC will work with Regional Entities to specify form, content, timing, and method of submitting reports and notices.

(1) The status of the review and assessment of all Possible Violations, Alleged Violations and Confirmed Violations of Reliability Standards by Registered Entities,

(2) The potential impact of any Alleged Violation or Confirmed Violation on the reliability of the Bulk Power System,

(3) Sanctions and Penalties,

(4) Remedial Action Directives imposed,

(5) Mitigation Plans, and

(6) The name of a Regional Entity staff person knowledgeable about the information to serve as a point of contact.

8.2 Reporting to Applicable Governmental Authorities and Public Disclosure

Within two (2) business days of receiving a report from a Regional Entity of a Possible Violation, Alleged Violation, or Confirmed Violation, NERC shall notify FERC of the Possible Violation, Alleged Violation or Confirmed Violation.

Where the report pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, NERC shall notify such other Applicable Governmental Authority, within two (2) business days of receiving a report of a Possible Violation, Alleged Violation or Confirmed Violation from the Regional Entity; provided, that NERC will not disclose any non-public U.S. compliance information that is subject to 18 C.F.R. §39.7(b)(4) to an Applicable Governmental Authority other than FERC without first obtaining permission from FERC for such disclosure and subject to any limitations placed by FERC on such disclosure. Likewise, NERC will not disclose non-public non-U.S. compliance information to an Applicable Governmental Authority (including FERC) without first obtaining permission from the Applicable Governmental Authority that has jurisdiction over the Registered Entity or portion of the Bulk Power System to which the non-public information pertains and subject to any limitations placed on such disclosure by such Applicable Governmental Authority or by other law of the applicable jurisdiction.

In any notice to, and request for permission to disclose compliance information from, FERC or another Applicable Governmental Authority pursuant to any provision of this Compliance Program, NERC will identify each Applicable Governmental Authority to which it proposes to disclose the information and the specific procedures that will be used for protecting from public disclosure any non-public compliance information that will be transferred to the other Applicable Governmental Authority or Authorities. The provisions of this paragraph do not apply to the provision by NERC to an Applicable Governmental Authority of information that is not directly related to a specific Registered Entity's compliance with a requirement of a Reliability Standard. NERC will publicly post on its website each Notice of Penalty, with any Critical Energy Infrastructure Information or other Confidential Information redacted (unless posting of the Critical Energy Infrastructure Information or Confidential Information has been determined to be permissible in accordance with Section 1500 of the Rules of Procedure), with the identity of the violator, together with any statement submitted by the Registered Entity, when NERC files the Notice of Penalty with FERC pursuant to Section 5.9.

NERC will provide reports quarterly to FERC and, where a report contains information pertaining to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority, on the status of all Possible, Alleged and Confirmed Violations for which mitigation activities have not been completed. All such reports to FERC and to other Applicable Governmental Authorities shall be provided in accordance with this Section.

9.0 DATA RETENTION AND CONFIDENTIALITY

9.1 Records Management

The Compliance Enforcement Authority records management policy shall provide for a routine and orderly process for the retention and disposal of electronic and paper records related to the Compliance Program, ensure verification of compliance with appropriate business, regulatory, and legal requirements and at a minimum conform to the data retention requirements of the Reliability Standards. The policy shall allow for the maintenance of records as required to implement the Compliance Program.

9.2 Retention Requirements

The Compliance Enforcement Authority records management policy will require that information and data generated or received pursuant to Compliance Program activities, including Compliance Audits, Self-Certifications, Spot Checks, Compliance Investigations, Self-Reports, Periodic Data Submittals, Exception Reporting, and Complaints, as well as a hearing process, will be retained for the longer of (i) five (5) years or (ii) any retention period specified in a Reliability Standard or by FERC or another Applicable Governmental Authority. The obligation to retain information and data commences upon the initiation of the Compliance Program activity that produces the data or information. If the information or data is material to the resolution of a controversy, the retention period for such data shall not commence until after the controversy is resolved.

Upon request from NERC, Regional Entities will provide to NERC copies of such information and data. NERC will retain the information and data in order to maintain a record of activity under the Compliance Program. In providing the information and data to NERC, the Regional Entity shall preserve any mark of confidentiality.

9.3 Confidentiality and Critical Energy Infrastructure Information

9.3.1 Definitions

Information or data generated or received pursuant to Compliance Program activities, including a hearing process, shall be treated in a confidential manner pursuant to the provisions of Section 1500 of the NERC Rules of Procedure. The terms "Confidential Information," "Confidential Business and Market Information," "Critical Energy Infrastructure Information," and "Critical Infrastructure" shall have the meanings stated in Appendix 2 to the NERC Rules of Procedure.

9.3.2 Protection of Confidential Information

The Compliance Enforcement Authority personnel (including any contractors, consultants and industry subject matter experts) and committee members, and participants in Compliance Program activities shall be informed of, and agree to comply with, Section 1500 of the NERC Rules of Procedure concerning Confidential Information.

9.3.3 Critical Energy Infrastructure Information

The Compliance Enforcement Authority will keep confidential all Critical Energy Infrastructure Information in accordance with Section 1500 of the NERC Rules of Procedures. Information deemed to be Critical Energy Infrastructure Information shall be redacted, in accordance with Section 1500 of the NERC Rules of Procedure, and shall not be released publicly.

ATTACHMENT 1

PROCESS FOR NON-SUBMITTAL OF REQUESTED DATA

FERC's regulations at 18 C.F.R §39.2(d) provide that each user, owner or operator of the Bulk Power System within the United States (other than Alaska and Hawaii) shall provide FERC, the ERO and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by FERC and set out in the rules of the ERO and each Regional Entity. In order to enforce this requirement, if data, information, or other reports (including Mitigation Plans) requested from a Registered Entity in connection with a compliance monitoring process or enforcement process are not received by the Required Date, the Compliance Enforcement Authority may sequentially execute the following steps for each Reliability Standard Requirement for which the Compliance Enforcement Authority has requested data, information, or other reports. However, upon a request from the Registered Entity submitted prior to the Required Date stating in reasonable detail the basis for the Registered Entity's need for additional time, the Compliance Enforcement Authority may afford the Registered Entity reasonable additional time to submit the data, information or report due to the scope or difficulty of the request or requirement for data, information or reports, the amount of the data, information or reports requested or required, or the form in which the data, information, or other reports has been requested or is required to be provided.

Step 1: The Compliance Enforcement Authority will issue a notification to the Registered Entity's designated contact for reliability matters, identifying the data, information or report that were requested or required and the Required Date and stating that the Required Date has passed and the Registered Entity should, within five (5) business days, either provide the data, information or report, or contact the Compliance Enforcement Authority with a proposed date by which the Registered Entity will provide the data, information or report. If the Compliance Enforcement Authority agrees with the Registered Entity on a revised date by which the Registered Entity will provide the data, information or report, the agreed revised date shall become the Revised Required Date.

Step2: If the Registered Entity does not provide a response to the notification in, and in accordance with, Step 1, within five (5) business days, or by a revised date as agreed to in Step 1, the Compliance Enforcement Authority will issue a notification to the Registered Entity's designated contact for reliability matters, with a copy to the Registered Entity's chief executive officer or equivalent, stating that if the data, information or report is not received within ten (10) business days, the Compliance Enforcement Authority may (i) implement a compliance monitoring process directed to the Registered Entity, or (ii) issue a Notice or other notification of Alleged Violation and Proposed Penalty or Sanction at the Severe Violation Severity Level to the Registered Entity for the Reliability Standard Requirement to which the requested or required

data, information or report relates.

Step 3: If the Registered Entity fails to produce the requested or required data, information or report in response to the notification in Step 2 within the ten (10) business day cure period set forth in the Step 2 notification, the Compliance Enforcement Authority may take any action of which the Registered Entity was notified in the Step 2 notification, including issuing a Notice or other notification of Alleged Violation and Proposed Penalty or Sanctionat the Severe Violation Severity Level for the Reliability Standard Requirement to which the requested or required data, information or report relates.

The process described in this Attachment 1 is intended to be applied where a Registered Entity does not respond by the Required Date to an initial request for data, information or reports in connection with a compliance monitoring and enforcement process and does not respond to subsequent requests (Steps 1 and 2 above) by the stated deadline. This process is not intended to apply where the Registered Entity responds, prior to the Required Date, to the initial request or requirement for data, information or reports with requests for clarification, definition of scope, or similar questions concerning the request or requirement for data, information or reports, or requests, prior to the Required Date, additional time to respond based on the scope or difficulty of the request or requirement for data, information or reports, the amount or extent of the data, information or reports requested or required, or the form in which the data, information or report is to be provided, and works with the Compliance Enforcement Authority in good faith to respond to the request or requirement for data, information or reports, as modified if appropriate by the Compliance Enforcement Authority based on questions raised by the Registered Entity.

ATTACHMENT 2 - HEARING PROCEDURES

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ATTACHMENT 2 - HEARING PROCEDURES

1.1 Applicability, Definitions and Interpretation

1.1.1 Procedure Governed

(a) The provisions set forth in this **Attachment 2** ("Hearing Procedures") shall apply to and govern practice and procedure before the Compliance Enforcement Authority in hearings in the United States conducted into:

(1) whether Registered Entities within the Compliance Enforcement Authority's Area of Responsibility have violated Reliability Standards, and

(2) if so, to determine the appropriate Mitigation Plans as well as any Remedial Action Directives, Penalties and/or sanctions in accordance with the NERC *Sanction Guidelines* and other applicable Penalty guidelines approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2).

(b) Any hearing conducted pursuant to these Hearing Procedures shall be conducted before a Hearing Officer and a Hearing Body established by the Compliance Enforcement Authority. Where the Hearing Body is comprised, in whole or in part, of industry stakeholders, the composition of the Hearing Body, after any recusals or disqualifications, shall be such that no two industry segments may control, and no single industry segment may veto, any decision by the Hearing Body on any matter brought before it for decision. Where the Hearing Body is comprised solely of independent members and an independent hearing Officer, decisions shall require a majority vote.

(c) The standard of proof in any proceeding under these Hearing Procedures shall be by a preponderance of the evidence. The burden of persuasion on the merits of the proceedings shall rest upon the Compliance Staff alleging noncompliance with a Reliability Standard, proposing a Penalty, opposing a Registered Entity's Mitigation Plan, or requiring compliance with a Remedial Action Directive.

(d) If a final order has been entered by the Hearing Body, or the Hearing Body has issued a ruling determining that there are no issues to be decided regarding the Alleged Violation, proposed Penalty amount, proposed Mitigation Plan or proposed Remedial Action Directive, or the Registered Entity and the Compliance Enforcement Authority have entered into a settlement agreement resolving the matters that are the subject of the hearing, the hearing shall be terminated by the Hearing Body and no further proceedings shall be conducted before the Hearing Body.

1.1.2 Deviation

To the extent permitted by law, any provision in these Hearing Procedures may be waived, suspended or modified by the Hearing Officer or the Hearing Body, for good cause shown, either upon the Hearing Officer's or the Hearing Body's own motion or upon the motion of any Participant.

1.1.3 Standards for Discretion

The Compliance Enforcement Authority's discretion under these Hearing Procedures shall be exercised to accomplish the following goals:

(a) Integrity of the Fact-Finding Process - The principal goal of the hearing process is to assemble a complete factual record to serve as a basis for a correct and legally sustainable ruling, decision or order.

(b) Fairness - Persons appearing in Compliance Enforcement Authority proceedings should be treated fairly. To this end, Participants should be given fair notice and opportunity to present explanations, factual information, documentation and legal argument. Action shall be taken as necessary to eliminate any disadvantage or prejudice to a Participant that would otherwise result from another Participant's failure to act diligently and in good faith.

(c) Independence - The hearing process should be tailored to protect against undue influence from any Person, Participant or interest group.

(d) Balanced Decision-Making - Decisions should be based solely on the facts and arguments of record in a proceeding and by individuals who satisfy the Compliance Enforcement Authority's conflict of interest policy.

(e) Impartiality - Persons appearing before the Hearing Body should not be subject to discriminatory or preferential treatment. Registered Entities should be treated consistently unless a reasonable basis is shown in any particular proceeding to depart from prior rulings, decisions or orders.

(f) Expedition - Proceedings shall be brought to a conclusion as swiftly as is possible in keeping with the other goals of the hearing process.

1.1.4 Interpretation

(a) These Hearing Procedures shall be interpreted in such a manner as will aid in effectuating the Standards for Discretion set forth in Section 1.1.3, and so as to require that all practices in connection with the hearings shall be just and reasonable.

(b) Any ruling, order or decision of the Hearing Officer referenced in these Hearing Procedures shall be made by the Hearing Body where the composition of the Hearing Body consists of independent members and an independent Hearing Officer.

(c) Unless the context otherwise requires, the singular of a term used herein shall include the plural and the plural of a term shall include the singular.

(d) To the extent that the text of a rule is inconsistent with its caption, the text of the rule shall control.

1.1.5 Definitions

Unless otherwise defined, as used in these Hearing Procedures, definitions in Appendix 2 of the NERC Rules of Procedure shall apply. For ease of reference, the following defined terms used in these Hearing Procedures are also set forth below:

"Clerk" shall mean an individual assigned by the Compliance Enforcement Authority to perform administrative tasks relating to the conduct of hearings as described in these Hearing Procedures.

"Compliance Enforcement Authority's Area of Responsibility" means the Compliance Enforcement Authority's Region. If a Regional Entity is the Compliance Enforcement Authority, the Compliance Enforcement Authority's Area of Responsibility is shown in Exhibit A to the delegation agreement between the Regional Entity and NERC.

"Critical Energy Infrastructure Information" means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that: (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

"Critical Infrastructure" means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

"Cyber Security Incident" means any malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.

"Director of Compliance" means the Director of Compliance of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority, who is responsible for the management and supervision of Compliance Staff, or his or her designee.

"Document" means, in addition to the commonly understood meaning of the term as information written or printed on paper, any electronically stored information, including writings, drawings, graphs, charts, photographs, sound recordings, images and other data or data compilations stored in any medium from which information can be obtained, and shall be translated by the producing party into reasonably usable form.

"ERO" or "Electric Reliability Organization" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the Bulk Power System in the United States, subject to Commission review. The organization may also have received recognition by Applicable Governmental Authorities in Canada and Mexico to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries.

"Evidentiary Hearing" means a hearing at which one or more Participants submits evidence for the record. A Testimonial Hearing is an Evidentiary Hearing, but an Evidentiary Hearing does not necessarily include the presentation of testimony by witnesses in person.

"FERC" means the Federal Energy Regulatory Commission.

"Hearing Body" means the body established or designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with these Hearing Procedures.

"Hearing Officer" means an individual employed or contracted by the Compliance Enforcement Authority and designated by the Compliance Enforcement Authority to preside over hearings conducted pursuant to these Hearing Procedures.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Body or by FERC to participate as an intervenor in a proceeding conducted pursuant to these Hearing Procedures, and as used in these Hearing Procedures shall include the members of the Compliance Staff of the Compliance Enforcement Authority that participate in a proceeding.

"Penalty" means and includes all penalties and sanctions, including but not limited to a monetary or non-monetary penalty; a limitation on an activity, function, operation or other appropriate sanction; or the addition of the Registered Entity or Respondent to a reliability watch list composed of major violators. Penalties must be within the range set forth in the NERC *Sanction Guidelines* approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2), and shall bear a reasonable relation to the seriousness of a Registered Entity's or Respondent's violation and take into consideration any timely efforts made by the Registered Entity or Respondent to remedy the violation.

"Person" means any individual, partnership, corporation, limited liability company, governmental body, association, joint stock company, public trust, organized group of persons, whether incorporated or not, or any other legal entity.

"Respondent" means the Registered Entity who is the subject of the Notice of Alleged Violation, contested Mitigation Plan or contested Remedial Action Directive that is the basis for the proceeding, whichever is applicable.

"Staff" or "Compliance Staff" means individuals employed or contracted by NERC or the Compliance Enforcement Authority who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties and Mitigation Plans.

"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies the Compliance Enforcement Authority's conflict of interest policy and is selected to assist in a proceeding by providing technical advice to the Hearing Officer and/or the Hearing Body.

"Testimonial Hearing" means an Evidentiary Hearing at which the witness or witnesses on behalf of one or more Participants appears in person to present testimony and be subject to cross-examination.

1.2 General Provisions including Filing, Service, Transcription and Participation

1.2.1 Contents of Filings

All filings made with the Hearing Body must contain:

(a) A caption that sets forth the title of the proceeding and the designated docket number or, if the filing initiates a proceeding, a space for the docket number;

(b) A heading that describes the filing and the Participant on whose behalf the filing is made;

(c) The full name, address, telephone number and email address of the Participant or the representative of the Participant making the filing;

(d) A plain and concise statement of any facts upon which the filing is based, which facts shall be supported by citations to the record of the hearing, if available, or other evidence; and

(e) The specific relief sought, which may be in the alternative, and the authority that provides for or otherwise allows the relief sought.

1.2.2 Form of Filings

(a) All filings shall be typewritten, printed, reproduced or prepared using a computer or other word or data processing equipment on white paper 8½ inches by 11 inches with inside text margins of not less than one inch. Page numbers shall be centered and have a bottom margin of not less than ½ inch. Line numbers, if any, shall have a left-hand margin of not less than ½ inch. The impression shall be on one side of the paper only and shall be double spaced; footnotes may be single spaced and quotations may be single spaced and indented.

(b) All pleadings shall be composed in either Arial or Times New Roman font, black type on white background. The text of pleadings or documents shall be at least 12-point. Footnotes shall be at least 10-point. Other material not in the body of the text, such as schedules, attachments and exhibits, shall be at least 8-point.

(c) Reproductions may be by any process provided that all copies are clear and permanently legible.

(d) Testimony prepared for the purpose of being entered into evidence shall include line numbers on the left-hand side of each page of text. Line numbers shall be continuous.

(e) Filings may include schedules, attachments or exhibits of a numerical or documentary nature which shall, whenever practical, conform to these requirements; however, any log,

graph, map, drawing, chart or other such document will be accepted on paper larger than prescribed in subparagraph (a) if it cannot be provided legibly on letter size paper.

1.2.3 Submission of Documents

(a) Where to File

Filings shall be made with the Clerk of the Compliance Enforcement Authority located at its principal office. The office will be open during the Compliance Enforcement Authority's regular business hours each day except Saturday, Sunday, legal holidays and any other day declared by the Compliance Enforcement Authority.

(b) When to File

Filings shall be made within the time limits set forth in these Hearing Procedures or as otherwise directed by the Hearing Officer or the Hearing Body. Filings will be considered made when they are date stamped received by the Clerk. To be timely, filings must be received no later 5:00 P.M. local time on the date specified.

(c) How to File

Filings may be made by personal delivery, mailing documents that are properly addressed with first class postage prepaid, or depositing properly addressed documents with a private express courier service with charges prepaid or payment arrangements made. Alternatively, filing by electronic means will be acceptable upon implementation of a suitable and secure system by the Compliance Enforcement Authority.

(d) Number of Copies to File

One original and five exact copies of any document shall be filed. The Clerk will provide each member of the Hearing Body with a copy of each filing.

(e) Signature

The original of every filing shall be signed by the Participant on whose behalf the filing is made, either by an attorney of the Participant or, by the individual if the Participant is an individual, by an officer of the Participant if the Participant is not an individual, or if the Participant is Staff, by a designee authorized to act on behalf of Staff.

(f) Verification

The facts alleged in a filing need not be verified unless required by these Hearing Procedures, the Hearing Officer or the Hearing Body. If verification is required, it must be under oath by a person having knowledge of the matters set forth in the filing. If any verification is made by an individual other than the signer, a statement must be included in or attached to the verification explaining why a person other than the signer is providing verification.

(g) Certificate of Service

Filings shall be accompanied by a certificate of service stating the name of the individuals served, the Participants whose interests the served individuals represent, the date on which service is made, the method of service and the addresses to which service is made. The certificate shall be executed by the individual who caused the service to be made.

1.2.4 Service

(a) Service List

For each proceeding, the Clerk shall prepare and maintain a list showing the name, address, telephone number, and facsimile number and email address, if available, of each individual designated for service. The Hearing Officer, Director of Compliance and the Registered Entity's compliance contact as registered with the Compliance Enforcement Authority, shall automatically be included on the service list. Participants shall identify all other individuals whom they would like to designate for service in a particular proceeding in their appearances or other filings. Participants may change the individuals designated for service in any proceeding by filing a notice of change in service list in the proceeding. Participants are required to update their service lists to ensure accurate service throughout the course of the proceeding. Copies of the service list may be obtained from the Clerk.

b) By Participants

Subject to the provisions of Section 1.5.10, any Participant filing a Document in a proceeding must serve a copy of the Document on each individual whose name is on the service list for the proceeding. Unless otherwise provided, service may be made by personal delivery, email, deposit in the United States mail properly addressed with first class postage prepaid, registered mail properly addressed with postage prepaid or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made.

(c) By the Clerk

The Clerk shall serve all issuances of the Hearing Officer and Hearing Body upon the members of the Hearing Body and each individual whose name is on the service list for the proceeding. Service may be made by personal delivery, email, deposit in the United States mail properly addressed with first class postage prepaid, registered mail properly addressed with postage prepaid or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made. The Clerk shall transmit a copy of the record of a proceeding to the ERO at the time the Compliance Enforcement Authority transmits to the ERO either (1) a Notice of Penalty, or (2) a Hearing Body final order that includes a Notice of Penalty.

(d) Effective Date of Service

Service by personal delivery or email is effective immediately. Service by mail or registered mail is effective upon mailing; service by a private express courier service is effective upon delivery to the private express courier service. Unless otherwise provided, whenever a Participant has the right or is required to do some act within a prescribed period after the service

of a document upon the Participant, four (4) days shall be added to the prescribed period when the document is served upon the Participant by mail or registered mail.

1.2.5 Computation of Time

The time in which any action is required to be done shall be computed by excluding the day of the act or event from which the time period begins to run, and by including the last day of the time period, unless the last day is a Saturday, Sunday, legal holiday or any other day upon which the office of the Compliance Enforcement Authority is closed, in which event it also shall be excluded and the date upon which the action is required shall be the first succeeding day that is not a Saturday, Sunday, legal holiday, or day upon which the office of the Compliance Enforcement Authority is closed.

1.2.6 Extensions of Time

Except as otherwise provided by law, the time by which a Participant is required or allowed to act may be extended by the Hearing Officer or Hearing Body for good cause upon a motion made before the expiration of the period prescribed. If any motion for extension of time is made after the expiration of the period prescribed, the Hearing Officer or Hearing Body may permit performance of the act if the movant shows circumstances sufficient to justify the failure to act in a timely manner.

1.2.7 Amendments

Amendments to any documents filed in a proceeding may be allowed by the Hearing Officer or the Hearing Body upon motion made at any time on such terms and conditions as are deemed to be just and reasonable.

1.2.8 Transcripts

(a) A full and complete record of all hearings, including any oral argument, shall be transcribed verbatim by a certified court reporter, except that the Hearing Officer may allow off-the-record discussion of any matter provided the Hearing Officer states the ruling on any such matter, and the Participants state their positions or agreement in relation thereto, on the record. The court reporter shall file a copy of each transcript with the Clerk. Upon receipt of a transcript from the court reporter, the Clerk shall send notice to the Participants stating that a transcript has been filed by the court reporter, the date or dates of the hearing that the transcript records, and the date the transcript was filed with the Clerk.

(b) Unless otherwise prescribed by the Hearing Officer, a Participant may file and serve suggested corrections to any portion of a transcript within fourteen (14) days from the date of the Clerk's notice that the transcript has been filed with the Clerk, and any responses shall be filed within ten (10) days after service of the suggested corrections. The Hearing Officer shall determine what changes, if any, shall be made, and shall only allow changes that conform the transcript to the statements being transcribed and ensure the accuracy of the record.

(c) The Compliance Enforcement Authority will pay for transcription services, for a copy of the transcript for the record and for a copy of the transcript for Staff. Any other Participant shall pay for its own copy of the transcript if it chooses to obtain one and, should any Participant seek to obtain a copy of the transcript on an expedited basis, it shall pay for the expedited transcription services.

1.2.9 Rulings, Notices, Orders and Other Issuances

Any action taken by the Hearing Officer or the Hearing Body shall be recorded in a ruling, notice, order or other applicable issuance, or stated on the record for recordation in the transcript, and is effective upon the date of issuance unless otherwise specified by the Hearing Officer or the Hearing Body. All notices of hearings shall set forth the date, time and place of hearing.

1.2.10 Location of Hearings and Conferences

All hearings and oral arguments shall be held at the principal office of the Compliance Enforcement Authority unless the Hearing Officer or Hearing Body designates a different location.

1.2.11 Participant Participation

Participants may appear at any hearing via teleconference subject to the approval of the Hearing Officer and, in the event of oral argument, the Hearing Body, except as required by Section 1.6.6. Staff may participate and be represented by counsel in hearings, and shall have the rights and duties of any Participant.

1.2.12 Interventions

(a) The Respondent(s) and Staff shall be Participants to the proceeding. Unless otherwise authorized by the Hearing Body or by FERC, no other Persons shall be permitted to intervene or otherwise become a Participant to the proceeding.

(b) The Hearing Body may allow a Person to intervene only if the Hearing Body determines that the Person seeking intervention has a direct and substantial interest in the outcome of the Alleged Violation, proposed Penalty or sanction, Mitigation Plan, or Remedial Action Directive that is the subject of the proceeding. Examples of a direct and substantial interest in the outcome shall include

(1) that the Person seeking intervention has received a Notice of Alleged Violation or a Remedial Action Directive involving the same Reliability Standard requirement(s) and arising out of the same event or occurrence as the existing Respondent(s) that is the subject of the proceeding, or

(2) that the Person seeking intervention will or may be contractually or legally liable to the original Respondent(s) for payment of all or a portion of the proposed Penalty or sanction that is the subject of the proceeding, provided, that after the Person seeking intervention sufficiently demonstrates it will or may be contractually or legally liable for payment of all or a portion of the proposed Penalty or sanction to be granted intervention, the Person granted intervention and

the existing Respondents will not be allowed to litigate in the proceeding whether the Person granted intervention is contractually or legally liable for payment of all or a portion of the proposed Penalty or sanction or the amount of the proposed Penalty or Sanction for which the Person granted intervention is or may be liable.

That the Person seeking intervention has received a Notice of Alleged Violation for the same Reliability Standard Requirement(s) as the original Respondent(s) but arising out of a different event or occurrence; or seeks to intervene to advocate an interpretation of the Reliability Standard Requirement(s) or provision(s) of the *Sanction Guidelines*, that are at issue in the proceeding, without more, shall not constitute a direct and substantial interest in the outcome and shall not be grounds on which the Hearing Body may allow the Person to intervene.

(c) A Person seeking intervention shall do so by filing a motion to intervene with the Clerk. The motion shall state the Person's interest in sufficient factual detail to demonstrate that the Person should be allowed to intervene pursuant to Section 1.2.12(b). The motion to intervene shall also state the Person's agreement to maintain the confidential and non-public nature of the hearing, including all pleadings and other Documents filed or exchanged in connection with the request for intervention. Any facts alleged in, or offers of proof made in, the motion to intervene shall be supported by affidavit or verification.

(d) The Clerk shall promptly provide copies of the motion to intervene to the Hearing Officer and the Participants. The Hearing Officer shall promptly set a time period, not to exceed seven (7) days, within which the Participants may file responses to the motion to intervene. Within seven (7) days following the end of the response period, the Hearing Officer shall issue a recommendation to the Hearing Body as to whether or not the motion to intervene should be granted.

(e) The Hearing Body may, within seven (7) days following the date of the Hearing Officer's recommendation, issue a decision granting or denying the motion to intervene. If the Hearing Body does not issue a decision granting or denying the motion to intervene within seven (7) days following the date of the Hearing Officer's recommendation, the Hearing Officer's recommendation shall become the decision of the Hearing Body and the motion to intervene shall be deemed granted or denied by the Hearing Body in accordance with the Hearing Officer's recommendation.

(f) The Hearing Officer, on motion of a Participant or on his or her own motion, or the Hearing Body, on recommendation by the Hearing Officer or its own motion, may stay or suspend the proceeding while a request to intervene, including a request to intervene filed directly with FERC, and including any appeal of the grant or denial of the request to intervene, is being resolved.

(g) A Person allowed to intervene and become a Participant to a proceeding shall be designated as a Respondent and deemed to be aligned with the existing Respondent(s), unless the Hearing Body, in the decision granting intervention, states that the Person allowed to intervene shall be deemed to be aligned with another Participant to the proceeding.

(h) A Person allowed to intervene and become a Participant to a proceeding is required to take the record and the procedural status of the proceeding as it stands on the date the Person's motion to intervene is granted by the Hearing Body.

(i) A Person may appeal a decision of the Hearing Body denying the Person's motion to intervene, and the Compliance Staff, the Respondent or any other Participant may appeal a decision granting or denying a motion to intervene, in accordance with Section 414 of the NERC Rules of Procedure. A notice of appeal shall be filed with the NERC director of enforcement no later than seven (7) days following the date of the decision of the Hearing Body granting or denying the motion to intervene.

1.2.13 Proceedings Closed to the Public

No hearing, oral argument or meeting of the Hearing Body shall be open to the public, and no notice, ruling, order or any other issuance of the Hearing Officer or Hearing Body, or any transcript, made in any proceeding shall be publicly released unless the ERO (within the U.S., in accordance with the authorization previously granted by FERC to release information about a non-public proceeding) or FERC (in the case of U.S.-related information) or another Applicable Governmental Authority (in the case of non-U.S.-related information) determine that public release is appropriate. Only the members of the Hearing Body, the Participants, the Hearing Officer and the Technical Advisors, if any, shall be allowed to participate in or obtain information relating to a proceeding.

1.2.14 Docketing System

The Clerk shall maintain a system for docketing proceedings. A docketed proceeding shall be created upon the filing of a request for a hearing. Unless NERC provides a different docketing system that will be used uniformly by the Compliance Enforcement Authorities, docket numbers shall be assigned sequentially beginning with a two digit number that relates to the last two digits of the year in which the docket is initiated, followed by a dash ("-"), followed by the letters "[RE]", followed by a dash ("-"), followed by a four digit number that will be "0001" on January 1 of each calendar year and ascend sequentially until December 31 of the same calendar year.

1.2.15 Representations Deemed to be Made in All Pleadings

A Participant presenting any pleading to the Hearing Officer or Hearing Body shall be deemed to certify that to the best of the Participant's knowledge, information and belief, formed after and based on an inquiry that is reasonable under the circumstances:

(a) the factual allegations set forth in the pleading have or will have support in the evidence or the Participant believes they will have support in the evidence after reasonable opportunity for further investigation or discovery;

(b) the denials in the pleading of factual allegations made by another Participant are warranted by or will be warranted by the evidence or, if specifically so identified, are reasonably based on belief or on a lack of information;

(c) the claims, defenses and other contentions set forth in the pleading are warranted based on the applicable Reliability Standard Requirement(s) or Rules of Procedure provisions; and

(d) the pleading is not being presented for any improper purpose, such as to harass, cause unnecessary delay, or needlessly increase the cost of the hearing or the cost incurred by any Participant.

1.2.16 Hold Harmless

A condition of a Participant invoking these Hearing Procedures and participating in a hearing is that the Participant agrees that the Compliance Enforcement Authority, including without limitation its members, board of directors or trustees, compliance committee, any other committees or subcommittees, Staff, contracted employees, Hearing Body members, Hearing Officers and Technical Advisors, shall not be liable, and shall be held harmless against the consequences of, or any action or inaction arising out of, the hearing process, or of any agreement reached in resolution of a dispute or any failure to reach agreement as a result of a proceeding. This "hold harmless" provision does not extend to matters constituting gross negligence, intentional misconduct or breach of confidentiality.

1.3 Initiation of the Hearing Process

1.3.1 Registered Entity's Option to Request a Hearing

(a) Except when contesting a Remedial Action Directive pursuant to Section 1.9 of these Hearing Procedures, a Registered Entity may file a statement, in accordance with Section 1.3.1(e), with the Compliance Enforcement Authority requesting a hearing if either:

(1) The Registered Entity files a response to a Notice of Alleged Violation that contests either the Alleged Violation, the proposed Penalty, or both; or

(2) The Compliance Staff submits to the Registered Entity a statement rejecting the Registered Entity's proposed revised Mitigation Plan submitted after Compliance Staff rejected the Registered Entity's initial proposed Mitigation Plan.

(b) A Registered Entity must file its hearing request within forty (40) days after

(1) the Registered Entity files its response to the Notice of Alleged Violation; or

(2) the Compliance Staff submits to the Registered Entity its statement identifying a disagreement with the Registered Entity's proposed Mitigation Plan, whichever is applicable.

(c) If the Registered Entity does not file a hearing request within the time period set forth in this Section, then the Registered Entity will be deemed to have agreed and waived any objection to the proposed Penalty, the Alleged Violation or the Compliance Staff's rejection of the revised Mitigation Plan, whichever is applicable.

(d) In accordance with Section 5.3 of the Compliance Program, a Notice of Alleged Violation issued to a Registered Entity or a Staff statement setting forth its rejection of a Registered Entity's proposed revised Mitigation Plan shall clearly state that the Registered Entity has the option to contest the Alleged Violation, proposed Penalty, or both, or the Compliance Staff's rejection of the proposed revised Mitigation Plan, using either the shortened hearing procedure pursuant to Section 1.3.4 or the general hearing procedure described in Sections 1.4 to 1.7.

(e) The Registered Entity's statement requesting a hearing shall:

(1) contain a plain and concise statement of the facts and arguments supporting the Registered Entity's position, as applicable, that it did not violate the Reliability Standard Requirement(s) set forth in the Notice of Alleged Violation, that the proposed Penalty or sanction is too high and should be reduced, or that the Registered Entity's proposed Mitigation Plan should be approved;

(2) state the relief that the Registered Entity requests the Hearing Body to grant; and

(3) state whether the Registered Entity requests the shortened hearing procedure or the general hearing procedure.

The Registered Entity's statement may set forth two or more alternative grounds on which the Registered Entity bases its position, as applicable, that it did not violate the Reliability Standard Requirement(s) set forth in the Notice of Alleged Violation, that the proposed Penalty or sanction is too high and should be reduced, or that the Registered Entity's proposed Mitigation Plan should be approved.

(f) If the Registered Entity (or any Respondent if there are more than one Respondent) requests the general hearing procedure, the general hearing procedure shall apply. If the Registered Entity (or all Respondents if there are more than one Respondent) requests the shortened hearing procedure, Compliance Staff and any other Participants shall submit a filing within five (5) days of the Registered Entity's hearing request that states whether Staff or such other Participant agrees to use the shortened hearing procedure. If Staff or another Participant makes a filing requesting the general hearing procedure, then the general hearing procedure shall apply; otherwise the shortened hearing procedure requested by the Registered Entity or Entities shall be used. Once either the general or shortened hearing procedure has been selected, the Participants shall not be allowed to revert to the non-selected hearing procedure unless the Participants mutually agree.

(g) A Registered Entity shall attach to a request for hearing whichever of the following are applicable:

(1) The Registered Entity's Self-Report of a violation;

(2) The Notice of Alleged Violation and the Registered Entity's response thereto; and/or

(3) The Registered Entity's proposed revised Mitigation Plan and the Compliance Staff's statement rejecting the proposed revised Mitigation Plan.

1.3.2 Compliance Staff's Response to Request for Hearing

(a) If the Registered Entity's request for hearing requests that the shortened hearing procedure be used, the Compliance Staff shall file a response stating whether it agrees to the use of the shortened hearing procedure.

(b) If the Registered Entity's request for hearing requests that the Registered Entity's proposed revised Mitigation Plan should be approved, the Compliance Staff shall file a response stating the Compliance Staff's position as to why the Registered Entity's proposed revised Mitigation Plan should not be approved and setting forth any additional terms that the Compliance Staff believes should be included in the Mitigation Plan.

(c) If the Registered Entity's request for hearing does not request that the shortened hearing procedure be used and does not request that the Registered Entity's proposed revised Mitigation Plan should be approved, the Compliance Staff may, but is not required to, file a response stating, as applicable, the basis for the Compliance Staff's position that the Registered Entity violated the Reliability Standard Requirement(s) specified in the Notice of Alleged Violation or that the proposed Penalty or sanction is appropriate under the *Sanction Guidelines* and should not be reduced.

(d) Any response by the Compliance Staff required or permitted by this Section shall be filed within fifteen (15) days after the date the request for hearing was filed, unless the Hearing Officer or Hearing Body allows a longer time to file the response.

1.3.3 Notice of Hearing

(a) The Clerk shall issue a notice of hearing not less than sixteen (16) days, and not more than twenty-one (21) days, after the Registered Entity files its request for hearing.

(b) The notice of hearing shall state whether the shortened hearing procedure or the general hearing procedure will be used.

(c) The notice of hearing shall identify the Hearing Officer and the date, time and place for the initial prehearing conference.

(1) If the shortened hearing procedure is to be used, the initial prehearing conference shall be set for a date within seven (7) days following the date of the notice of hearing.

(2) If the general hearing procedure is to be used, the initial prehearing conference shall be set for a date within fourteen (14) days following the date of the notice of hearing.

1.3.4 Shortened Hearing Procedure

The shortened hearing procedure shall be as set forth in this Section. The rules applicable to the general hearing procedure shall apply to the shortened hearing procedure unless the context of such a rule is inconsistent with the procedure set forth in this Section or otherwise renders it inapplicable to the shortened hearing procedure. The rules concerning ex parte communications

in Section 1.4.7 are hereby expressly made applicable to the shortened hearing procedure under this Section.

The Hearing Body shall utilize a Hearing Officer to preside over the shortened hearing procedure in accordance with Section 1.4.2. But, no Testimonial Hearing will be held in the shortened hearing procedure and the Participants will not present witness testimony or file briefs, except that briefs on exceptions and briefs in reply to exceptions may be allowed pursuant to subsection (g). Instead, the following events shall take place within the following periods:

(a) The initial prehearing conference shall be held within seven (7) days after the date on which the notice of hearing is issued. In addition to any other matters set forth in Section 1.5.2 that may apply, the initial prehearing conference will be used to develop a schedule for the preparation and submission of comments in accordance with subsections (c) through (e).

(b) Within ten (10) days after the date on which the notice of hearing is issued, Staff shall make Documents available to the Registered Entity for inspection and copying pursuant to Section 1.5.7.

(c) Within twenty-one (21) days after the initial prehearing conference, the Staff shall file:

(1) initial comments stating Staff's position on all issues and the rationale in support of its position, including all factual and legal argument;

(2) all Documents that Staff seeks to introduce in support of its position that have not already been submitted in the proceeding; and

(3) a verification attesting to the truthfulness of the facts alleged in the filing.

(d) Within fourteen (14) days of Staff's initial comment filing pursuant to subsection (c), the Registered Entity shall file:

(1) responsive comments stating the Registered Entity's position on all issues and the rationale in support of its position, including all factual and legal argument, which comment also may respond to Staff's initial comments;

(2) all Documents that the Registered Entity seeks to introduce in support of its position that have not already been submitted in the proceeding; and

(3) a verification attesting to the truthfulness of the facts alleged in the filing.

(e) Within seven (7) days after the Registered Entity's responsive comment filing pursuant to subsection (d), Staff shall file reply comments that shall be limited in scope to responding to the Registered Entity's responsive comments and be supported by a verification attesting to the truthfulness of the facts alleged in the filing. Staff shall not submit any additional Documents in support of its position as part of this filing except upon motion and good cause shown. If Staff is allowed to file additional Documents in support of its position based upon such a

motion, the Registered Entity shall have the right to file additional Documents in support of its position that are responsive to the additional Documents that Staff is allowed to file provided that any additional Registered Entity filing also shall be verified.

(f) The Hearing Officer shall issue an initial opinion within twenty-one (21) days after the Staff's reply comments filing or any additional filing by the Registered Entity pursuant to subsection (e).

(g) If either Participant requests, the Hearing Officer shall allow each Participant to file, within seven (7) days after the Hearing Officer's initial opinion, exceptions to the Hearing Officer's initial opinion in a brief designated "brief on exceptions" in accordance with Section 1.7.5 and within seven (7) days thereafter, a reply brief designated "brief in reply to exceptions."

(h) The Hearing Body shall strive, but is not required, to issue a final order within one hundred twenty (120) days of the notice of hearing.

The Hearing Officer or Hearing Body may modify any time period set forth within this Paragraph as warranted by the circumstances but it will be the objective of the Hearing Body to issue the final order within one hundred twenty (120) days of the notice of hearing.

1.4 General Hearing Procedure

1.4.1 [Intentionally Left Blank]

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1.4.2 Hearing Officer

(a) The Compliance Enforcement Authority shall utilize a Hearing Officer to preside over each hearing conducted pursuant to these Hearing Procedures, provided that the Hearing Officer's actions shall be subject to the authority of the Hearing Body as set forth in Section 1.4.3. Members of the Hearing Body may attend any aspect of the hearing.

(b) The Hearing Officer is responsible for the conduct of the hearing, including administering the hearing from the initial prehearing conference through the issuance of the Hearing Officer's initial opinion, any administrative hearing functions thereafter, and submission of the matter to the Hearing Body for final decision through the presentation to the Hearing Body of an initial opinion. The Hearing Officer shall have those duties and powers necessary to those ends, consistent with and as further enumerated in these Hearing Procedures, including the following:

(1) To administer oaths and affirmations;

(2) To schedule and otherwise regulate the course of the hearing, including the ability to call to recess, reconvene, postpone or adjourn a hearing;

(3) Consistent with any timing or deadline requirements imposed by these Hearing Procedures or by applicable law, to separate any issue or group of issues from other issues in a proceeding and treat such issue(s) as a separate phase of the proceeding;

(4) Consistent with any timing or deadline requirements imposed by these Hearing Procedures or by applicable law, to modify any time period, if such modification is in the interest of justice and will result in no undue prejudice to any other Participant;

(5) To supervise and issue orders concerning discovery;

(6) To conduct prehearing conferences, status hearings and Evidentiary Hearings;

(7) To hear argument on all objections, motions and other requests, and to rule upon all objections, motions and other requests that do not result in the final determination of the proceeding;

(8) To rule on and receive evidence;

(9) To call upon a Participant to produce further evidence that is material and relevant to any issue;

(10) To issue protective orders pursuant to Section 1.5.10;

(11) To issue initial opinions; and

(12) To ensure that hearings are conducted in a full, fair and impartial manner, that order is maintained and that unnecessary delay is avoided in the disposition of the proceedings.

(c) The Compliance Enforcement Authority shall disclose the employment history and professional affiliations of the Hearing Officer within two (2) days of the Hearing Officer's assignment to the proceeding, and Participants to the hearing may raise objections to the Hearing Officer's participation in accordance with Section 1.4.5.

1.4.3 Hearing Body

(a) The composition of the Hearing Body, after any recusals or disqualifications, shall be such that no two industry segments may control, and no single industry segment may veto, any decision of the Hearing Body on any matter brought before it for decision.

(b) The Hearing Body is vested with the authority to issue a final order resolving the issue(s) in all cases. To that end:

(1) Upon receiving a filing by a Participant, the Clerk shall promptly send a notice to the members of the Hearing Body identifying the date of the filing and the Participant making the filing and briefly describing the nature of the filing. Any member of the Hearing Body may request of, and shall receive from, the Clerk, a

copy of any filing by a Participant. The Hearing Body shall not receive Documents made available by Staff for inspection and copying by the Respondent, or other responses to discovery between the Participants, unless such Documents are placed into the record pursuant to Section 1.6.7.

(2) The Clerk shall send all issuances of the Hearing Officer to the members of the Hearing Body.

(3) The Hearing Body or any individual member thereof may, but is not required to, attend any prehearing conference, status hearing or Evidentiary Hearing, and/or to submit questions to the Hearing Officer to submit to a Participant or any witness at any hearing. At any prehearing conference or hearing attended by a member of the Hearing Body, any member of the Hearing Body may ask questions directly of any Participant or witness.

(4) The Hearing Body shall have the same authority as the Hearing Officer, as set forth in these Hearing Procedures, to require the Participants or any individual Participant to: (i) address a specific issue in testimony, evidence or briefs; (ii) present oral argument on an issue; (iii) file pre-Evidentiary Hearing memorandums; or (iv) produce further evidence that is material and relevant to any issue. To this end, the Hearing Body shall be entitled to issue questions or requests for information to any Participant or any witness at any time until the issuance of a final order.

(5) To the extent that the Hearing Body disagrees with any issuance or ruling of the Hearing Officer, it may, on its own motion or upon petition for interlocutory review meeting the requirements of Section 1.4.4, reverse or modify the issuance or ruling in whole or in part, or take any other action as may be appropriate.

(6) The Hearing Body shall resolve the issue(s) in every hearing through the issuance of a final order. In issuing a final order, the Hearing Body shall consider the Hearing Officer's initial opinion but shall have the authority to reject, modify or approve the initial opinion in whole or in part.

1.4.4 Interlocutory Review

(a) A Participant shall be allowed to seek interlocutory review by the Hearing Body of any ruling of the Hearing Officer where the ruling for which interlocutory review is sought presents an extraordinary circumstance which makes prompt review necessary to prevent prejudice to a Participant's ability to present its position in the proceeding. Failure to seek such review shall not operate as a waiver of any objection to such ruling.

(b) Unless good cause is shown or unless otherwise ordered by the Hearing Officer or the Hearing Body, the Participant seeking review shall file a petition for interlocutory review within fourteen (14) days after the date of the action that is the subject of the petition. The petition shall contain, in a separately identified section, a demonstration that the ruling for which interlocutory review is sought presents an extraordinary circumstance which makes prompt review necessary to prevent prejudice to the Participant's ability to present its position in the proceeding. The

petition shall be filed with any offer of proof and supported by references to the record, or by affidavit if based on facts that do not appear in the record. Responses to petitions for interlocutory review shall be filed within seven (7) days after service of the petition. No replies to responses shall be allowed.

(c) The Hearing Officer shall file a report to the Hearing Body within fourteen (14) days from the filing of the petition. The Hearing Officer's report shall set forth the relevant facts and other background information relating to the ruling on which interlocutory review is sought, the basis for the Hearing Officer's ruling, a summary of the Participants' arguments on the petition for interlocutory review, and the recommendation of the Hearing Officer for the disposition of the petition by the Hearing Body.

(d) On review of a Hearing Officer's ruling, the Hearing Body may affirm or reverse the ruling in whole or in part, and may take any other just and reasonable action with respect to the ruling, such as declining to act on an interlocutory basis. The Hearing Body may reject the petition for interlocutory review on the grounds that the ruling for which review is sought does not present an extraordinary circumstance which makes prompt review necessary to prevent prejudice to a Participant's ability to present its position in the proceeding, without considering or ruling on the substance of the petitioner's arguments.

(e) Issuance of a ruling on a petition for interlocutory review shall require (i) a quorum (as defined in Section 1.7.8) of the Hearing Body, and (ii) majority vote of the members of the Hearing Body voting on the final order (which number of members voting shall not be less than a quorum). Petitions to rehear or reconsider the Hearing Body's action taken on interlocutory review shall not be allowed. Filing and disposition of a petition for interlocutory review of a ruling of the Hearing Officer shall not suspend or otherwise delay a hearing or any other scheduled dates in the proceeding except as authorized by the Hearing Officer or the Hearing Body based on a finding of exceptional circumstances.

(f) A non-Participant that has been ordered by the Hearing Officer pursuant to Section 1.5.8 to produce or provide Documents, information or testimony, and has failed to obtain the relief sought from the Hearing Officer through filing objections to or a motion to quash the order, shall also be entitled to seek interlocutory review by the Hearing Body of the Hearing Officer's order, with respect to (i) whether the non-Participant is within the class of Persons subject to such orders pursuant to Section 1.5.8, and (ii) the reasonableness of the Hearing Officer's order to produce or provide Documents, information or testimony.

1.4.5 Disqualification

(a) A Hearing Officer, Technical Advisor or member of the Hearing Body shall recuse himself or herself from a proceeding if participation would violate the Compliance Enforcement Authority's applicable conflict of interest policy.

(b) Any Participant may file a motion to disqualify or for recusal of a Hearing Officer, Technical Advisor or member of the Hearing Body from a proceeding on grounds of a conflict of interest, an ex parte communication prohibited by section 1.4.7, or the existence of other circumstances that could interfere with the impartial performance of his or her duties. The Participant shall set forth and support its alleged grounds for disqualification by affidavit. A

motion for disqualification shall be filed within fifteen (15) days after the later of: (1) the time when the Participant learns of the facts believed to constitute the basis for disqualification; or (2) the time when the Participant is notified of the assignment of the Hearing Officer or Technical Advisor.

(c) The Hearing Officer shall issue a proposed ruling for the Hearing Body's consideration upon the filing of a motion for disqualification unless the Hearing Officer is the subject of the motion. The Hearing Body, without the participation of any member who is the subject of the motion, shall issue a final ruling on the motion. If the Hearing Officer recuses himself or herself or is disqualified, the Hearing Body will appoint a replacement Hearing Officer. To ensure fairness to the Participants and expedite completion of the proceeding when a replacement Hearing Officer is appointed after a hearing has commenced, the replacement Hearing Officer may recall any witness or may take other steps necessary to ensure familiarity with any part or all of the record.

(d) If a quorum (as defined in Section 1.7.8) of the Hearing Body does not remain after any recusals and rulings on motions for disqualification, then the Compliance Enforcement Authority shall appoint at least the number of new members to the Hearing Body necessary to create a quorum. The new member(s) shall serve on the Hearing Body through the conclusion of the proceeding but not thereafter. Any new member of the Hearing Body shall be subject to the provisions applicable herein to all Hearing Body members.

1.4.6 Technical Advisor

(a) The Hearing Officer and/or the Hearing Body may elect to use one or more Technical Advisors to assist in any proceeding. Such an election may be made at any time during the course of a proceeding. Any Staff member who serves as a Technical Advisor shall not have been involved in or consulted at any time in regard to any Compliance Staff investigation, determination of a Possible Violation, Alleged Violation or Penalty, or assessment of a Registered Entity's proposed Mitigation Plan that resulted in the proceeding in which technical advice would be rendered, and shall not be a member of Staff participating in the proceeding on which such technical advice would be rendered.

(b) If the Hearing Officer or Hearing Body uses a Technical Advisor to assist in any hearing, the Hearing Officer or Hearing Body shall disclose the identity, employment history and professional affiliations of the Technical Advisor within two (2) days of the Technical Advisor's assignment to the proceeding, and Participants to the hearing may raise objections to the Technical Advisor's participation in accordance with Section 1.4.5.

1.4.7 No Ex Parte Communications

(a) Once a Registered Entity requests a hearing pursuant to Section 1.3.1:

(1) neither the Hearing Body, the Hearing Officer, nor the Technical Advisor(s), if any, may communicate either directly or indirectly with any Person concerning any issue in the proceeding outside of the hearing process; except that

(2) the Hearing Body, the Hearing Officer, and the Technical Advisor(s), if any, may communicate outside of the hearing process either directly or indirectly with a Participant or a Participant's representative:

(A) in writing if the writing is simultaneously provided to all Participants; or

(B) orally if a representative for every Participant is present in person or by telephone;

(C) subject to the requirement that the substance of any ruling on any issue discussed shall be memorialized on the record or by the issuance of a notice or ruling, and that any Participant objecting to the ruling shall have the opportunity to state its objection on the record.

(b) Exceptions

(1) The proscription in subsection (a)(1) does not prohibit members of the Compliance Staff from communicating with the Registered Entity, and representatives, agents or employees thereof on any topic, provided that any member of the Compliance Staff involved in any such communication relating to the subject matter of the proceeding may not be, and may not subsequently serve as, a Technical Advisor.

(2) The proscription in subsection (a)(1) does not prohibit communications between or among members of the Hearing Body, the Hearing Officer and any Technical Advisor.

(3) The proscription in subsection (a)(1) does not prohibit communications between the Hearing Officer or members of the Hearing Body to the Clerk for the purpose of transmitting documents, giving instructions to the Clerk, or discussing scheduling and other procedural matters relating to the proceeding.

(4) The proscription in subsection (a)(1) does not prohibit communications between or among the Clerk, the Hearing Body and representatives of the Compliance Enforcement Authority for purposes of establishing the hearing forum.

(c) Any member of the Hearing Body, the Hearing Officer or any Technical Advisor who receives or who makes or knowingly allows a communication prohibited by this Section shall, within seven (7) days of the communication, file and serve on the Participants in the proceeding a notice of ex parte communication setting forth the date, time and place of communication, a summary of the substance and nature of the communication and all responses thereto, and a list of each Person who made or received the communication and, if the communication or any response thereto was in writing, a copy of the written communication shall be attached.

1.4.8 Appearances

(a) Participants shall file written appearances within seven (7) days after the notice of hearing is issued. A Participant's written appearance shall identify the name(s) of each

individual authorized to represent the Participant in the proceeding exclusive of witnesses. An individual may appear on his or her own behalf. A corporation, limited liability company, association, partnership or governmental body may appear by any bona fide officer or designee who has the authority to act on behalf of the Participant. A Participant also may appear by an attorney.

(b) A Participant's written appearance shall state, with respect to each individual that the Participant identifies for service, the individual's name, address, telephone number, and facsimile number and email address, if available, where service shall be made.

A Participant may withdraw any individual from the Participant's representation or otherwise change the identity of individuals authorized to represent the Participant in a proceeding by filing a notice of a change in service list.

(c) Any attorney appearing on behalf of a Participant shall be licensed to practice law and in good standing before the Supreme Court of the United States or the highest court of any State, territory of the United States or the District of Columbia. All representatives appearing before the Hearing Body or Hearing Officer shall conform to the standards of ethical conduct required of practitioners before the courts of the United States.

(d) Individuals representing Participants in any hearing also shall enter their appearances at the beginning of the hearing by stating their names, addresses, telephone numbers and email addresses orally on the record.

1.4.9 Failure to Appear or Exercise Diligence

The failure of any Participant to appear during any hearing without good cause and without notification may be grounds for dismissal or deciding against the interests of such Participant.

1.4.10 Consolidation of Proceedings

(a) In the event that more than one Registered Entity receives a Notice of Alleged Violation for the same event or occurrence, and each Registered Entity selects the general hearing procedure described in Sections 1.4 to 1.7, the Hearing Body on its own motion or on motion of a Participant may exercise its discretion to examine the actions of all such Registered Entities in a single proceeding as long as an initial opinion has not been rendered by the Hearing Officer pursuant to Section 1.7.4 in any proceeding to be consolidated.

(b) A Participant may file a motion to consolidate into a single proceeding Alleged Violations of different Reliability Standards against a single Respondent, and related contests of Penalties or Mitigation Plans, arising out of the same event or occurrence. Such consolidation may be allowed in the discretion of the Hearing Officer or Hearing Body, as applicable.

1.5 Prehearing Procedure

1.5.1 [Intentionally left blank]

1.5.2 Prehearing Conference

(a) The Hearing Officer shall hold at least one prehearing conference, which may be the initial prehearing conference or a subsequently scheduled prehearing conference, for the following purposes:

(1) Preliminarily identify the issues and discuss the anticipated form of the hearing;

(2) Discuss a schedule for any discovery to be conducted and address any discovery issues that are raised at that time;

(3) Explore the possibility of obtaining admissions of fact and of the authenticity of Documents that would avoid unnecessary proof;

(4) Develop a schedule for the preparation and submission of evidence and witness testimony, including the disclosure of witnesses and exhibits and whether the use of pre-filed testimony may not be appropriate, in advance of the Evidentiary Hearing;

(5) Develop a schedule or schedules for any anticipated motions;

(6) Schedule a date(s) for the Evidentiary Hearing, which shall be within ninety (90) days of the prehearing conference described in this subsection, unless a different date or dates is specified by the Hearing Officer or the Hearing Body and with the consent of all Participants or for good cause shown; and

(7) Address such other matters as may aid in the simplification of the evidence and disposition of the proceeding.

(b) The Hearing Officer shall also hold a final prehearing conference prior to the Evidentiary Hearing, for the purpose of discussing:

(1) the anticipated duration of the hearing;

(2) the scheduling of witnesses' appearances to testify;

(3) the issues anticipated to be presented at the hearing;

(4) whether prehearing memoranda should be filed and if so, the schedule; and

(5) any other matters identified by the Hearing Officer for the management of the Evidentiary Hearing.

Participants may submit to the Hearing Officer, at least ten (10) days prior to the scheduled date of the final prehearing conference, a proposed list or lists of matters to be discussed at the final prehearing conference.

1.5.3 Summary Disposition

(a) Availability

A Hearing Officer, on the Hearing Officer's own motion or on the motion of a Participant, may issue an initial opinion granting, in whole or in part, summary disposition if it appears that there are no issues of material fact and a Participant is entitled to issuance of a final order in its favor.

(b) Motion for Summary Disposition and Responses

(1) A Participant moving for summary disposition must clearly identify the material facts that are not in dispute, demonstrate that there are no other material facts in dispute, and demonstrate that on the basis of the undisputed material facts, the Participant is entitled to issuance of a final order in its favor.

(2) A Participant opposing a motion for summary disposition must clearly identify in its response to the motion the material facts that the Participant contends remain in dispute, and/or explain why the moving Participant is not entitled to issuance of a final order in its favor even though there are no disputed issues of material fact.

(c) Summary Disposition on the Hearing Officer's Own Motion

If the Hearing Officer is considering summary disposition in the absence of a Participant motion, the Hearing Officer shall request the Participants to identify in writing any issues of material fact and to comment on the proposed disposition. Factual information in the Participants' comments shall be supported by affidavit. Following review of the Participants' comments, if it still appears to the Hearing Officer that there are no genuine issues of material fact, the Hearing Officer may proceed without an Evidentiary Hearing. The Hearing Officer shall, however, allow the Participants the opportunity to file briefs.

(d) Hearing Officer's Initial Opinion Granting Summary Disposition

When the Hearing Officer issues an initial opinion granting summary disposition in whole or in part, the ruling shall set forth the rationale for the grant. An initial opinion of the Hearing Officer granting summary disposition shall be confirmed, rejected or modified in a final order issued by the Hearing Body.

1.5.4 Status Hearings

Any Participant may request, and the Hearing Officer may call, a status hearing at any time subsequent to the initial prehearing conference to address issues that have arisen between the Participants or other matters relevant to the conduct of the hearing. Such issues may include, but are not limited to, discovery disputes and scheduling matters. A Participant requesting a status hearing to resolve a dispute shall include in its request a certification that it has made a good faith effort to resolve the dispute with the other Participant(s) before requesting the status hearing. The Hearing Officer shall direct the Clerk to issue a notice of status hearing that sets forth the date, time and place for the hearing, and identifies the matters to be addressed at the hearing.

1.5.5 Motions and Responses

(a) Unless otherwise provided in these Hearing Procedures or by the procedural schedule established by the Hearing Officer or Hearing Body, a Participant may file a motion at any time requesting any relief as may be appropriate. Unless the Hearing Officer allows a motion to be made orally on the record, motions shall be filed in writing. Motions based on facts that do not appear of record shall be supported by affidavit.

(b) Unless otherwise specified by the Hearing Officer or Hearing Body, responses to motions shall be filed within fourteen (14) days after service of the motion, and replies to responses shall be filed within seven (7) days after service of the responses. A Hearing Officer or Hearing Body may deny dilatory, repetitive, or frivolous motions without awaiting a response. Unless otherwise ordered by a Hearing Officer or Hearing Body, the filing of a motion does not stay the proceeding or extend any scheduled dates in the proceeding.

1.5.6 Experts

(a) A Participant may employ an expert(s) to testify or consult in a proceeding. Any expert utilized in either capacity shall sign an agreement evidencing the expert's understanding and acknowledgement of the non-public nature of the proceeding and that unauthorized public disclosure of information obtained in connection with the expert's participation in the proceeding is prohibited.

(b) The Participant employing the expert shall propose the agreement for approval by a motion, and its approval shall be subject, in addition to consideration of any objections by other Participants, to ensuring that appropriate safeguards are maintained to protect the confidentiality of the proceeding and the information disclosed therein.

1.5.7 Inspection and Copying of Documents in Possession of Staff

(a) Documents to be Available for Inspection and Copying

(1) Within twenty-five (25) days after the date the request for hearing is filed, Staff shall make available for inspection and copying by the other Participants, all Documents prepared or obtained by Staff through or in connection with any compliance monitoring processes that led to the institution of proceedings. Such Documents shall include but are not limited to:

(A) requests for information to the Respondent;

(B) every written request, including e-mail, directed to persons not employed by the Compliance Enforcement Authority to provide information or Documents or to be interviewed;

(C) the Documents provided in response to any such requests described in (A) and (B) above;

(D) all transcripts of testimony recorded during the Staff investigation and all exhibits to the transcript;

(E) all other Documents obtained from the Respondent; and

(F) all other Documents obtained from persons not employed by the Compliance Enforcement Authority.

The sole grounds on which Staff is authorized to withhold Documents from inspection and copying are the bases set forth in subsection 1.5.7(b); provided, however, that the Documents made available for inspection and copying need not include (i) exact copies of Documents the Respondent previously provided to Staff, and (ii) any Documents provided to the Respondent with or as part of the Notice of Alleged Violation, Notice of Penalty, assessment of proposed Mitigation Plan or Remedial Action Directive.

(2) Where there are Participants in a proceeding in addition to a single Respondent and Compliance Staff, the Hearing Officer or Hearing Body shall oversee the Staff's designation of Documents to be produced to such other Participants and the development, execution and enforcement of any protective order deemed necessary.

(3) Staff shall promptly inform the Hearing Officer and each other Participant if, after the issuance of a notice of hearing, requests for information are issued by Staff related to the same compliance monitoring process(es) that led to the institution of the proceeding. If Staff receives Documents pursuant to a request for information after Staff has made Documents available for inspection and copying as set forth in subsection (a)(1), the additional Documents shall be made available to the Participants not later than fourteen (14) days after Staff receives such Documents. If a date for the Evidentiary Hearing has been scheduled, Staff shall make the additional Documents available to the other Participants not less than ten (10) days before the Evidentiary Hearing. If Staff receives such Documents ten or fewer days before the Evidentiary Hearing is scheduled to begin or after the Evidentiary Hearing begins, Staff shall make the additional Documents available immediately to the other Participants.

(4) Nothing in subsection (a)(1) shall limit the discretion of the Compliance Enforcement Authority to make any other Document available to the Participants or the authority of the Hearing Officer to order the production of any other Documents or information by any Participant.

(b) Documents That May Be Withheld by Staff

(1) Staff may withhold a Document from inspection and copying by a Participant if:

(A) the Document is privileged to the Compliance Enforcement Authority or constitutes attorney work product of counsel for the Compliance

Enforcement Authority (in applying this provision, the attorney-client privilege shall be recognized as absolute and any demand for production of attorney work product shall be granted only after a showing of substantial need by the Respondent or other Participant);

(B) the Document is an examination or inspection report, an internal memorandum, or other note or writing prepared by a Staff member that will not be offered in evidence or otherwise relied on by Staff in the hearing;

(C) the Document would disclose

(i) an examination, investigatory or enforcement technique or guideline not otherwise made public of the Compliance Enforcement Authority, a federal, state, or foreign regulatory authority, or a self-regulatory organization;

(ii) the identity of a source, including a federal, state, or foreign regulatory authority or a self-regulatory organization, that furnished information or was furnished information on a confidential basis regarding an investigation, an examination, an enforcement proceeding, or any other type of civil or criminal enforcement action; or

(iii) an examination, an investigation, an enforcement proceeding, or any other type of civil or criminal enforcement action under consideration by, or initiated by, the Compliance Enforcement Authority, a federal, state, or foreign regulatory authority, or a self-regulatory organization; or

(D) the Hearing Officer grants leave to withhold a Document or category of Documents as not relevant to the subject matter of the proceeding, or for other good cause shown.

Provided, that where a Document contains information of the type listed in subsections (A), (B), (C) or (D) that is capable of being redacted, Staff shall make the Document available for inspection and copying by the other Participants in redacted form.

(2) Nothing in subsections (b)(1)(B), (C) or (D) authorizes Staff to withhold a Document, or a part thereof, that contains exculpatory evidence. Nothing in subsection (b)(1) requires Staff to withhold a Document from disclosure.

(c) Withheld Document List

At the time it is required to make Documents available for inspection and copying, Staff shall also provide to the Hearing Officer, the Respondent and any other Participant to which Documents are being made available, a list of Documents withheld by Staff pursuant to

subsection (b)(1), with a statement of the grounds that support withholding the Document. Upon review, for good cause shown, the Hearing Officer may order Staff to make any Document withheld, other than a Document that is subject to the attorney-client privilege, available to the other Participants for inspection and copying.

(d) Timing of Inspection and Copying

Except as set forth in this Section, the Hearing Officer shall determine the schedule of production of Documents for inspection and copying, provided that the Hearing Officer may modify any time period for production set forth in this Section as warranted by the circumstances.

(e) Place and Time of Inspection and Copying

Documents subject to inspection and copying pursuant to this Section shall be made available to the Respondent and other Participants for inspection and copying at the Compliance Enforcement Authority office where the Documents are ordinarily maintained, or at such other office as the Hearing Officer, in his or her discretion, shall designate, or as the Participants otherwise agree. A Participant shall be given access to the Documents at the Compliance Enforcement Authority's offices during normal business hours. A Participant shall not be given custody of the Documents or be permitted to remove the Documents from the Compliance Enforcement Authority's offices, other than copies of Documents made available by the Compliance Enforcement Authority for that purpose.

(f) Copying Costs

A Participant may obtain a photocopy of all Documents made available for inspection. A Participant shall be responsible for the cost of photocopying. Unless otherwise ordered by the Hearing Officer, charges for copies made at the request of a Participant shall be at a rate to be established by the Compliance Enforcement Authority.

(g) Failure to Make Documents Available — Harmless Error

In the event that a Document required to be made available to a Participant pursuant to this Section is not made available by Staff, no rehearing or amended decision of a proceeding already heard or decided shall be required where the failure to make the Document available was harmless error. Should a dispute arise as to whether a rehearing or amended decision is required due to the failure of Staff to produce a Document, the burden shall be on Staff to show that such failure was harmless error. The Hearing Officer, or, upon review, the Hearing Body shall determine whether the failure to make the Document available was harmless error.

1.5.8 Other Discovery Procedures

(a) In addition to the production of Documents by Staff for inspection and copying by Respondent and other Participants pursuant to Section 1.5.7, the Participants shall be entitled to utilize all other discovery methods provided for in Rules 402 through 409 of the FERC Rules of Practice and Procedure, 18 C.F.R. §385.402 through 385.409, including data requests, written interrogatories and requests for production of Documents or things, depositions by oral

examination, requests for inspection of Documents and other property, requests for admissions, and requests for issuance of orders to one or more Registered Entities to produce Documents for inspection and copying or at the hearing or to provide testimony by an authorized representative in deposition or at the hearing.

(b) Unless otherwise directed by the Hearing Officer or Hearing Body upon motion by a Participant, or by the Hearing Officer, or by the Hearing Body on its own motion, such discovery, and the resolution of any disputes concerning such discovery, shall be conducted in accordance with the provisions of Rules 402 through 410 and 510(e) of the FERC Rules of Practice and Procedure, 18 C.F.R. §385.402 through 385.410 and 385.510(e), which are hereby incorporated by reference into these Hearing Procedures, subject to the following limitations and modifications to such Rules:

(1) The provisions of subsections (d), (e) and (f) of Section 1.5.7 shall apply to any such discovery.

(2) Rule 403(b)(2) (18 C.F.R. §385.403(b)(2)) and Rule 410(d)(2) (18 C.F.R. §385.410(d)(2)) shall not be applicable.

(3) The Hearing Officer and the Hearing Body have the authority to issue orders to compel the appearance by or production of Documents or information by, only a Person that (i) is a Participant or (ii) is a Registered Entity (including an authorized representative thereof) that is not a Participant. The Hearing Officer and the Hearing Body do not have authority to require a United States marshal or deputy marshal to serve an order to produce or provide Documents, information or testimony.

(4) References to "subpoena" in Rules 404, 409, 410 and 510(e) shall be deemed to be to an order to a non-Participant Registered Entity to produce or provide Documents, information or testimony.

(5) References to the "Commission" in Rules 402 through 410 and 510(e) shall be to FERC except as follows:

(i) the references in Rules 402(a), 404(b)(1) and 405(b), the second reference in Rule 410(d), and the references in Rule 510(e)(1) and (2) shall be deemed to be to the Hearing Body,

(ii) the reference in Rule 385.406(b)(4) to "Commission trial staff" shall be deemed to be to Compliance Staff, and

(iii) the reference in Rule 510(e)(3) shall be deemed to be to the Hearing Officer or Hearing Body.

(6) Unless otherwise ordered by the Hearing Officer or Hearing Body, a data request, set of interrogatories, request for production of Documents or things, request for inspection of Documents or other property, request for admissions, or order to

produce or provide Documents, information or testimony, shall not specify a due date or response date that is fewer than 21 days from the date of service of the request or date of the order.

(7) A list of withheld Documents, if any, shall be provided by any Participant required to produce Documents, at the time the Documents are required to be produced, to the Hearing Officer and to each Participant entitled to receive production of the Documents. Upon review, for good cause shown, the Hearing Officer may order the Participant to make any Document withheld available to any other Participant or Participants for inspection and copying.

(8) In the event a Document or information required to be produced or provided by a Participant pursuant to discovery is not produced or provided by the Participant, no rehearing or amended decision of a proceeding already heard or decided shall be required where the failure to produce or provide the Document or information was harmless error. Should a dispute arise as to whether a rehearing or amended decision is required due to the failure of a Participant to produce or provide a Document or information, the burden shall be on the Participant that failed to produce or provide the Document or information to show that such failure was harmless error. The Hearing Officer or, upon review, the Hearing Body shall determine whether the failure to make the Document available was harmless error.

(9) Unless otherwise ordered by the Hearing Officer or Hearing Body, all such discovery shall be requested, scheduled and conducted so as to be completed within six (6) months following the date the request for hearing was filed.

(10) Notwithstanding subsections (b)(6) and (b)(9), however, if the shortened hearing procedure in Section 1.3.4 is used in a proceeding, the Hearing Officer, on his or her own motion or on motion of a Participant, shall establish a schedule for discovery, including response periods for responding to discovery requests, that are consistent with the expedited nature of the proceeding contemplated by the shortened hearing procedure.

(c) The Hearing Officer's ruling on all motions relating to disputes concerning such discovery shall consider the following objectives:

(1) full disclosure of all relevant Documents and information;

(2) the exercise of due diligence in the conduct of discovery by a Participant; and

(3) disallowing use of discovery as a means to delay the proceeding or to harass or burden any other Participant.

1.5.9 Pre-Evidentiary Hearing Submission of Testimony and Evidence

(a) Unless the Hearing Officer orders otherwise and with the exception of (i) any adverse Participant examination pursuant to Section 1.6.16 and (ii) the testimony and Documents of a non-Participant provided pursuant to an order to produce or provide Documents, information or testimony, all witness direct testimony to be submitted in an Evidentiary Hearing must be prepared in written form, may have exhibits, schedules and attachments thereto, and shall be filed in advance of the Evidentiary Hearing pursuant to a schedule determined by the Hearing Officer, as it may be amended.

(b) Where a Participant intends to use a Document or other demonstrative evidence that has not been filed as part of written testimony in the conduct of cross-examination (other than Documents that are to be produced by a non-Participant at the hearing pursuant to an order to produce Documents), the Participant intending to use such Document or demonstrative evidence shall provide it to the other Participants and the Hearing Officer at least three (3) business days prior to the date at which the witness will be cross-examined at a Testimonial Hearing.

(c) Compliance Staff shall file the Documents it intends to offer into evidence as its direct case, including the written testimony of its witnesses along with exhibits, schedules and attachments thereto, first. The Registered Entity shall file the Documents it intends to offer into evidence as its direct case, which also may be responsive to Staff's direct case, including the written testimony of its witnesses along with exhibits, schedules and attachments thereto, second. Staff shall file as its rebuttal case the Documents it intends to offer into evidence in response to the Registered Entity's direct case, including the written testimony of its witnesses along with exhibits, schedules and attachments thereto, third.

(d) If appropriate due to the number and/or complexity of the issues, the Hearing Officer may allow for the Registered Entity to submit a rebuttal case that responds to Staff's rebuttal case, in which event the Hearing Officer shall also allow Staff to submit a surrebuttal case that responds to the Registered Entity's rebuttal case.

(e) Each round of evidence shall be limited in scope to responding to the preceding round of evidence, except that the Registered Entity's direct case may exceed the scope of Staff's direct case if necessary for the Registered Entity to set forth its direct case fully.

(f) The Participants shall file the Documents they intend to offer into evidence in accordance with the Hearing Officer's schedule, as it may be amended. Such filings of written testimony and other evidence in advance of the Evidentiary Hearing shall not entitle the Documents to be admitted into the evidentiary record. The Participants must offer their witnesses' testimony and other proposed evidence for admission into the evidentiary record during the Evidentiary Hearing.

(g) Any Participant who fails, without good cause shown, to comply with the Hearing Officer's schedule for the filing of written testimony and other evidence in advance of the Evidentiary Hearing may be limited in the presentation of its evidence during the Evidentiary Hearing or have its participation in the Evidentiary Hearing otherwise restricted by the Hearing Officer to avoid undue prejudice and delay.

1.5.10 Protective Orders

(a) All proceedings conducted pursuant to these Hearing Procedures, and any written testimony, exhibits, other evidence, transcripts, comments, briefs, rulings and other issuances, shall be non-public and shall be held in confidence by all Participants, except as the ERO (within the U.S., in accordance with the authorization previously granted by FERC to release information about a non-public proceeding) or FERC (in the case of U.S.-related information) or another Applicable Governmental Authority (in the case of non-U.S.-related information) authorizes or directs public disclosure of any portion of the record. In addition to this general proscription, at any time during a proceeding, the Hearing Officer, on his or her own motion or on the motion of any Participant or of any non-Participant ordered to produce Documents, information or testimony, may enter a protective order to designate as proprietary and protect the confidential, proprietary or trade secret nature of any data, information or studies, or any other information the public release of which may cause a security risk or harm to a Participant.

(b) The following types of information will be considered entitled to protection through a protective order:

(1) Confidential Business and Market Information, including information that is proprietary, commercially valuable, or competitively sensitive;

(ii) Critical Energy Infrastructure Information;

(iii) information related to a Cyber Security Incident;

(iv) personnel information that identifies or could be used to identify a specific individual, or that reveals personnel, financial, medical or other personal information;

(v) audit work papers;

(vi) investigative files or Documents that would disclose investigative techniques of Staff, any Compliance Enforcement Authority, the ERO or any federal, state or foreign regulatory authority.

Nothing in this subsection 1.5.10(b) shall require Staff to produce any Documents it is entitled to withhold under subsection 1.5.7(b).

(c) A motion for a protective order shall specify the proposed expiration date for the proprietary status of the data, Documents or information, if any, and shall propose requirements or safeguards to be met for individuals participating in the proceeding to review the protected information while maintaining its proprietary status.

(d) A Document submitted and marked as proprietary, or a statement made at a hearing and identified as proprietary, shall be afforded proprietary treatment pending the timely submission of a motion to protect the confidential, proprietary or trade secret nature of that Document or statement and a ruling on such a motion by the Hearing Officer.

(e) The protective order shall identify the data, Documents or information that will be accorded proprietary treatment; the individuals participating in the proceeding, by category or otherwise, entitled to view the proprietary information; and the requirements, conditions or safeguards that must be met before an individual may view the information.

(f) A public redacted version of each Document and transcript that contains information that is protected pursuant to this Section must be filed with the proprietary version and must be served on each Participant for distribution to those individuals participating in the proceeding who are not entitled to view the proprietary information.

(g) Should it be necessary to address proprietary information during a hearing, the Hearing Officer shall, while the information is being addressed, close the hearing to all individuals other than those entitled to view or hear the proprietary information in accordance with the protective order.

1.5.11 Pre-Evidentiary Hearing Memorandum

(a) The Hearing Officer or the Hearing Body may request the submission of memoranda prior to the Evidentiary Hearing that set forth each Participant's position on the issue(s) in dispute, the key facts and arguments, the applicable Reliability Standard, rules, orders or other authority, and such other matters as may be directed by the Hearing Officer or the Hearing Body.

(b) The purpose of such memoranda will be to aid the Hearing Officer and Hearing Body in preparation for the Evidentiary Hearing. A Participant will not be deemed to have waived any issue, fact or argument that is not set forth in a pre-Evidentiary Hearing memorandum.

(c) The Hearing Officer may establish word limitations on such submissions.

1.5.12 Certification of Questions to the NERC Board of Trustees

(a) Should a hearing present a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the proceeding in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the NERC Board of Trustees appropriate, the Hearing Officer, on his or her own motion or on motion of a Participant, may recommend to the Hearing Body that it certify, or the Hearing Body on its own motion may decide to certify, the question to the Board of Trustees for determination pursuant to Section 412 of the Rules of Procedure.

(b) If the Hearing Officer, on his or her own motion, or the Hearing Body, on its own motion, wishes to present a question to the Hearing Body for certification to the NERC Board of Trustees, the Hearing Officer shall first provide the Participants the opportunity to submit memoranda addressing whether the question should be certified and the precise terms of the question to be certified.

(c) If a Participant files a motion requesting, or the Hearing Officer determines on his or her own motion, that a question should be certified to the Board of Trustees, the Hearing Officer shall submit a written recommendation on the matter to the Hearing Body. If the request for certification is based on the motion of a Participant, the Hearing Officer shall also submit to the Hearing Body the motion and any answers to the motion that were filed. If the request for

certification is on the Hearing Officer's own motion, the Hearing Officer shall also submit to the Hearing Body the Participants' memoranda that were filed pursuant to subsection (b).

(d) Questions of fact presented by the particular matter in dispute in a hearing shall not be the subject of a certification to the Board of Trustees.

(e) The Hearing Body shall determine, based on the criteria specified in subsection (a), whether the proposed question shall be certified to the Board of Trustees for determination. To certify the proposed question, the Hearing Body must determine that the question is a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the proceeding, in whole or in part, and that there are extraordinary circumstances that make prompt consideration of the question by the Board of Trustees appropriate. If the Hearing Body determines that the proposed question should be certified to the Board of Trustees, the Hearing Body shall also determine whether the hearing should be suspended, in whole or in part, while the question is pending before the Board of Trustees for determination.

(f) As provided in Rule of Procedure Section 412, the Board of Trustees may decide to reject a proposed certification from a Hearing Body.

(f) If the Board of Trustees accepts certification of a question and issues a determination on the question, the hearing shall proceed following the determination in accordance with the Board of Trustees' decision.

1.6 Procedure at Evidentiary Hearing

1.6.1 Purpose of Evidentiary Hearing

The purpose of the Evidentiary Hearing shall be to admit the Participants' evidence into the record, and for each Participant to have the opportunity to cross-examine the other Participant's witnesses. A schedule for briefs, unless waived by the Participants, shall be set at the conclusion of the Evidentiary Hearing.

1.6.2 Order of Receiving Evidence

In all proceedings Compliance Staff shall open and close.

1.6.3 Opening and Closing Statements

Opening and closing statements will not be made during the Evidentiary Hearing as a matter of course except that such statements may be allowed when requested by a Participant, and shall be required when requested by the Hearing Officer or the Hearing Body. Any Participant's request for such statements, or a Hearing Officer or Hearing Body notice requiring such statements, shall be made at least ten (10) days in advance of the start of the Evidentiary Hearing.

1.6.4 Right of Participant to Present Evidence

Subject to compliance with the requirements of these Hearing Procedures concerning the timing of submission of written testimony and other evidence, a Participant has the right to present such

evidence, to make such objections and arguments, and to conduct such cross-examination as may be necessary to assure the true and full disclosure of the facts.

1.6.5 Exhibits

(a) All material offered in evidence, except oral testimony allowed by the Hearing Officer or the testimony of a non-Participant pursuant to an order to produce or provide Documents, information or testimony, shall be offered in the form of an exhibit.

(B) Each exhibit must be marked for identification. A Participant must provide the court reporter with two (2) copies of every exhibit that the Participant offers into evidence, and will provide copies of any exhibit not served in advance of the Evidentiary Hearing to the Participants and the Hearing Officer.

1.6.6 Witness Attendance at Testimonial Hearing

(a) Each witness shall attend the Testimonial Hearing in person unless a Participant has been informed in advance of the Testimonial Hearing that all other Participants waive cross-examination of the witness and neither the Hearing Officer nor the members of the Hearing Body have any questions for the witness, in which event the witness does need not be present at the Testimonial Hearing.

(b) A person compelled to appear, voluntarily testifying, or making a statement may be accompanied, represented and advised by an attorney.

(c) All testimony offered at a Testimonial Hearing is to be under oath or affirmation. If a witness is not required to attend the Testimonial Hearing, then the Participant on whose behalf the witness prepared testimony shall submit an affidavit of the witness attesting to the veracity of the witness' testimony, and the Participant shall be allowed to introduce the witness' testimony, and the exhibits, schedules and attachments thereto, into the evidentiary record based on such affidavit.

1.6.7 Admission of Evidence

(a) Compliance Staff shall offer its exhibits into evidence first and the Registered Entity second, unless the Participants agree otherwise.

(b) Except for witnesses who are not required to attend the Testimonial Hearing, the Participants shall call each witness in turn. Following the witness' swearing in, the witness shall attest to the veracity of his or her written testimony. The witness may identify any language and/or figures in his or her written testimony or exhibits that the witness would like to change or correct. Subject to objection, such changes or corrections may be allowed at the Hearing Officer's discretion for the purpose of obtaining a full, accurate and complete record without imposing undue delay or prejudice on any Participant. The Participant whose witness has made changes or written corrections to written testimony and exhibits shall file corrected copies with the Clerk and provide corrected copies to the Hearing Officer and other Participant.

(c) Once a witness has attested to the veracity of his or her testimony, the Participant on whose behalf the witness is testifying shall move for admission of the witness' testimony,

including all exhibits, schedules and attachments thereto, into evidence. Other Participants may object to the introduction of the witness' testimony, or any part thereof, as set forth in Section 1.6.11. Subject to the Hearing Officer's ruling on the objection, the witness' testimony shall be admitted into evidence.

(d) The witness shall then be turned over for cross-examination by other Participants, and for any questions by the Hearing Officer or any member of the Hearing Body, in accordance with Section 1.6.14, and then for redirect examination in accordance with Section 1.6.15. Witnesses shall be cross-examined on all previously-served testimony (direct, rebuttal or surrebuttal) when they first take the witness stand.

(e) Except (i) in exceptional cases and upon a showing of good cause and (ii) witnesses testifying pursuant to an order to produce or provide Documents, information or testimony issued to a non-Participant, no witness shall be allowed to testify unless a Participant has served the witness' written testimony in advance of the Testimonial Hearing in accordance with the schedule established by the Hearing Officer. Due to the undue prejudice such surprise witness testimony would impose on other Participants, it is the Compliance Enforcement Authority's policy to discourage witness testimony at a Testimonial Hearing when a Participant has not served the witness' written testimony in advance of the Testimonial Hearing. If such testimony is allowed, sufficient procedural steps shall be taken by the Hearing Officer to provide the other Participants with a fair opportunity for response and cross-examination.

1.6.8 Evidence that is Part of a Book, Paper or Document

(a) When relevant and material matter offered in evidence is embraced in a book, paper or Document containing other matter that is not material or relevant, the Participant offering the same must plainly designate the matter offered as evidence, and segregate and exclude the material not offered to the extent practicable.

(b) If the material not offered is in such volume as would unnecessarily encumber the record, such book, papers or Document will not be received in evidence but may be marked for identification and, if properly authenticated, the relevant or material matter may be read into the record, or, if the Hearing Officer so directs, a separate copy of such matter in proper form shall be offered as an exhibit.

(c) All other Participants shall be afforded an opportunity to examine the book, paper or Document and to offer in evidence in like manner other portions thereof if found to be material and relevant.

1.6.9 Stipulations

The Participants may stipulate to any relevant fact or the authenticity of any relevant Document. Stipulations may be made in writing or entered orally in the record. Notwithstanding stipulation, the Hearing Officer may require evidence of the facts stipulated in order to provide a complete evidentiary record on which to base the final order.

1.6.10 Official Notice

(a) Where relevant and material to the subject matter of the proceeding, the Hearing Officer may, upon request of a Participant, take official notice of any of the following:

(1) Rules, regulations, administrative rulings and orders, written policies of governmental bodies, and rulings and orders of other Compliance Enforcement Authorities.

(2) The orders, transcripts, exhibits, pleadings or any other matter contained in the record of other docketed proceedings of the Compliance Enforcement Authority.

(3) State, provincial and federal statutes and municipal and local ordinances.

(4) The decisions of state, provincial and federal courts.

(5) Generally recognized scientific or technical facts within the specialized knowledge of the Compliance Enforcement Authority.

(6) All other matters of which the courts of the United States may take judicial notice.

(b) All requests to take official notice shall be submitted in advance of the Evidentiary Hearing in accordance with a schedule established by the Hearing Officer. Before ruling on a request to take official notice, the Hearing Officer shall afford the other Participant opportunity to object or to show the contrary to the matter for which official notice is requested.

(c) An accurate copy of any item officially noticed shall be introduced into the record in the form of an exhibit presented by the Participant requesting official notice unless waived by the Participants and approved by the Hearing Officer. Any information officially noticed and not presented as an exhibit shall be set forth in a statement on the record.

1.6.11 Admissibility of Evidence

(a) Any evidence offered, including that included in a book, paper or Document pursuant to Section 1.6.8, shall be subject to appropriate and timely objections. Any Participant objecting to the admission or exclusion of evidence must state the grounds for objection.

(b) The admission of evidence shall not be limited by the generally recognized rules of evidence as applied in the courts of the United States or of the states, although the Hearing Officer may take such rules of evidence into consideration in ruling on the admissibility of evidence. The Hearing Officer will exercise discretion in the admission of evidence based upon arguments advanced by the Participants, and shall admit evidence if it is of a type commonly relied upon by reasonably prudent persons in the conduct of their affairs. The Hearing Officer may only exclude material from the record in response to a motion or objection by a Participant.

(c) Formal exception to a ruling on admissibility of evidence need not be taken to be preserved.

1.6.12 Offer of Proof

Any Participant who has had evidence excluded may make an offer of proof on the record. The offer of proof may consist of a statement made on the record of the substance of the evidence that the Participant claims would have been adduced, or any written or documentary exhibit that the Participant sought to introduce. Any such exhibit shall be retained as part of the record.

1.6.13 Reservation of Evidentiary Ruling

(a) The Hearing Officer shall rule upon any objection to the admissibility of evidence at the time the objection is made; provided that the Hearing Officer has discretion to reserve such a ruling or to require the Participants to file written arguments in relation thereto.

(b) If the Hearing Officer reserves the ruling, appropriate steps shall be taken during the Evidentiary Hearing to ensure a full, complete and accurate record in relation to the objected to evidence in the event the objection to the evidence's admissibility is overruled.

1.6.14 Cross-Examination

(a) Each witness shall be tendered for cross-examination subsequent to the admission of the witness' testimony into the evidentiary record. Each Participant shall have the right to cross-examine each witness of any other Participants. A Participant may waive cross-examination of any witness. Leading questions are permitted on cross-examination.

(b) The credibility of a witness may be attacked by any Participant, including the Participant calling the witness.

(c) The Hearing Officer and any member of the Hearing Body may ask the witness questions following the conclusion of the witness' cross-examination by the other Participant, and prior to the witness' redirect examination pursuant to Section 1.6.15.

1.6.15 Redirect Examination

A Participant shall be entitled to conduct redirect examination of each of the Participant's witnesses who are subject to cross-examination or questions of the Hearing Officer or a member of the Hearing Body. Any redirect examination shall be limited in scope to the witness' cross-examination and questions of the Hearing Officer and members of the Hearing Body.

1.6.16 Examination of Adverse Participant

(a) Any Participant may call any adverse Participant, or any employee or agent thereof, during the Testimonial Hearing to provide oral testimony on the Participant's behalf, and may conduct such oral examination as though the witness were under cross-examination.

(b) If a Participant intends to call an adverse Participant for examination, it shall give notice to the Hearing Officer and all other Participants setting forth the grounds for such examination at least fourteen (14) days in advance of the Testimonial Hearing, and the Participant who, or whose employee or agent, is sought to be called shall file any objection at least seven (7) days in advance of the Testimonial Hearing.

(c) Any Participant may conduct oral examination of a witness testifying pursuant to an order to produce or provide Documents, information or testimony issued to a non-Participant, as though the witness were under cross-examination.

1.6.17 Close of the Evidentiary Record

(a) The Hearing Officer shall designate the time at which the evidentiary record will be closed, which will typically be at the conclusion of the Evidentiary Hearing.

(b) Evidence may not be added to the evidentiary record after it is closed, provided that, prior to issuance of the Hearing Body's final order, the Hearing Officer may reopen the evidentiary record for good cause shown by any Participant. For the purpose of reopening the evidentiary record, newly discovered evidence that is material to the issues in dispute and could not, by due diligence, have been discovered prior to or during the Evidentiary Hearing, shall constitute good cause.

1.7 Post- Evidentiary Hearing Procedure

1.7.1 Briefs

(a) At the close of the Evidentiary Hearing, Participants may file initial and reply briefs.

(b) Briefs shall be concise, and, if in excess of twenty (20) pages, excluding appendices, shall contain a table of contents. Statements of fact should be supported by record citations.

(c) The Hearing Officer will prescribe the time for filing briefs, giving due regard to the nature of the proceeding, the extent of the record, the number and complexity of the issues, and the objective of expedition.

(d) Unless the Hearing Officer prescribes otherwise, all Participants shall file initial and reply briefs simultaneously.

(e) Participants' reply briefs shall be limited in scope to responding to arguments and issues raised in other Participants' initial briefs.

(f) The Hearing Officer may allow oral closing statements to be made on the record in lieu of briefs.

(g) The Hearing Officer may establish reasonable word limitations applicable to briefs.

1.7.2 Other Pleadings

Post-hearing pleadings other than briefs are permitted, but, absent good cause shown, such pleadings may not seek to introduce additional evidence into the record.

1.7.3 Draft Initial Opinions

The Hearing Officer may permit or require Participants to file draft initial opinions that set forth the Participants' proposed findings of fact and conclusions.

1.7.4 Hearing Officer's Initial Opinion

(a) At the conclusion of the Evidentiary Hearing, and following the submission of initial and reply briefs and draft orders, if any, the Hearing Officer shall prepare an initial opinion for the Hearing Body's review and consideration.

(b) The initial opinion shall include a statement of each finding and conclusion, and the reasons or basis therefore, for all material issues presented on the record. The initial opinion also shall contain the appropriate orders to dispose of the proceeding, including any Penalty, Mitigation Plan or Remedial Action Directive that the Hearing Officer proposes the Hearing Body require.

(c) The initial opinion shall note if the subject of the proceeding has been deemed to involve a Cyber Security Incident, if any information in the proceeding was deemed to be Critical Energy Infrastructure Information, or if any information in the proceeding is the subject of a protective order pursuant to Section 1.5.10.

1.7.5 Exceptions

(a) Within twenty-one (21) days after service of the initial opinion, or such other time as is fixed by the Hearing Officer, any Participant may file exceptions to the initial opinion in a brief designated "brief on exceptions" and, within fourteen (14) days after the time for filing briefs on exceptions or such other time as is set by the Hearing Officer, any Participant may file as a reply, a "brief in reply to exceptions."

(b) Exceptions and replies thereto with respect to statements, findings of fact or conclusion in the initial opinion must be specific and must be stated and numbered separately in the brief. With regard to each exception, the Participant must specify each error asserted, and include a concise discussion of any policy considerations applicable and any other evidence and arguments in support of the Participant's position. Suggested replacement language for all statements to which exception is taken must be provided. Exceptions and arguments may be filed (1) together in one brief; or (2) in two separate documents, one designated as the brief containing arguments, and the other designated "Exceptions," containing the suggested replacement language.

(c) Arguments in briefs on exceptions and replies thereto shall be concise and, if in excess of twenty (20) pages, shall contain a table of contents.

(d) Participants shall not raise arguments in their briefs in reply to exceptions that are not responsive to any argument raised in any other Participant's brief on exceptions.

(e) Statements of fact should be supported by citation to the record.

(f) The Hearing Officer may establish reasonable word limitations applicable to arguments included in briefs on exception and briefs in reply to exceptions. Such word limitations shall not apply to a Participant's proposed replacement language.

(g) Unless good cause is shown, if a Participant does not file a brief on exceptions, or if a Participant filed a brief on exceptions that does not object to a part of the initial opinion,

the Participant shall be deemed to have waived any objection to the initial opinion in its entirety, or to the part of the initial opinion to which the Participant did not object, whichever applies. This provision shall not prohibit the Participant, in its brief in reply to exceptions, from responding to another Participant's exceptions to such part of the initial opinion or from proposing alternative replacement language to the replacement language proposed by the other Participant for such part of the initial opinion.

1.7.6 Oral Argument

(a) The Hearing Body may elect to hear oral argument. If oral argument is held without briefs having been filed, Participants will be given the opportunity to present argument on all issues.

(b) If oral argument is held where briefs have been filed, argument may be limited to issues identified by the Hearing Body. The Hearing Body will direct the Clerk to issue a notice of oral argument that identifies the date, time, place and issues for the argument.

(c) The presentation of written materials or visual aids is permitted at oral argument. To the extent such materials or aids contain factual information, they shall be supported by the record, and contain accurate citations to the record. Such materials or aids may not contain new calculations or quantitative analyses not presented in the record, unless they are based on underlying data contained in the record. Copies of all written materials or visual aids to be presented at oral argument shall be served on all Participants not less than forty-eight (48) hours prior to the time and date of oral argument.

1.7.7 Additional Hearings

After the evidentiary record has been closed but before issuance of the Hearing Body's final order, the Hearing Officer may reopen the evidentiary record and hold additional hearings. Such action may be taken on the Hearing Officer's or the Hearing Body's own motion if there is reason to believe that reopening is warranted by any changes in conditions, or by the need to compile a complete evidentiary record on which to base the final order. Any Participant may file a motion to reopen the record, which shall contain the reasons for reopening, including material changes in conditions or the identification of additional evidence that should be included in the record, and a brief statement of proposed additional evidence and an explanation why such evidence was not previously adduced.

1.7.8 Hearing Body Final Order

(a) Following the receipt of the initial opinion, any exceptions and replies thereto, and oral argument, if any, the Hearing Body shall issue its final order.

(b) Issuance of a final order shall require (i) a quorum of the Hearing Body, which shall be (after any recusals, disqualifications and appointments of replacement members) at least fifty (50) percent of the number of members normally assigned to the Hearing Body, and (ii) majority vote of the members of the Hearing Body voting on the final order (which number of members voting shall not be less than a quorum).

(c) The Hearing Body shall strive, but shall not be required, to issue its final order within thirty (30) days following the last to occur of the initial opinion, exceptions or replies thereto, or oral argument. The final order may adopt, modify, amend or reject the initial opinion in its entirety or in part. The final order shall include a statement of each finding and conclusion, and the reasons or basis therefore, for all material issues presented on the record.

(d) The Hearing Body will base its determinations in the final order on the record. The final order also shall contain the appropriate orders to dispose of the proceeding, including any Penalty, Remedial Action Directive or Mitigation Plan required.

(e) The final order shall note if the subject of the proceeding has been deemed to involve a Cyber security Incident, if any information in the proceeding was deemed to be Critical Energy Infrastructure Information, or if any information in the proceeding is the subject of a protective order issued pursuant to Section 1.5.10.

(f) The service of the final order shall include a notice informing the Participants of their appeal rights to the ERO or to FERC, as applicable.

1.7.9 The Record

The Clerk shall maintain the record for all dockets. The record shall include any of the following, including all attachments thereto and Documents filed therewith, that exist in any docket:

(1) Notice of Alleged Violation and Registered Entity's response thereto;

(2) Registered Entity's proposed Mitigation Plan and Staff's statement identifying its disagreement(s) therewith;

(3) Remedial Action Directives and the Registered Entity's notice contesting the Remedial Action Directive;

(4) Registered Entity's request for a hearing;

(5) Participant filings, motions, and responses;

(6) Notices, rulings, orders and other issuances of the Hearing Officer and Hearing Body;

(7) Transcripts;

(8) Evidence received;

(9) Written comments submitted in lieu of written testimony;

(10) Matters officially noticed;

(11) Offers of proof, objections and rulings thereon, and any written or documentary evidence excluded from the evidentiary record;

(12) Pre-Evidentiary Hearing memorandums, briefs, and draft opinions;

(13) Post-hearing pleadings other than briefs;

(14) The Hearing Officer's initial opinion;

(15) Exceptions to the Hearing Officer's initial opinion, and any replies thereto;

(16) The Hearing Body's final order and the Clerk's notice transmitting the final order to the Participants;

(17) All notices of ex parte communications; and

(18) Any notifications of recusal and motions for disqualification of a member of the Hearing Body or Hearing Officer or Technical Advisor and any responses or replies thereto.

1.7.10 Appeal

A Participant or a Regional Entity acting as the Compliance Enforcement Authority, may appeal a final order of the Hearing Body to NERC in accordance with Rule of Procedure Section 409.

1.8 Settlement

Settlements may be entered into at any time pursuant to Section 5.6 of the NERC Compliance Monitoring and Enforcement Program and the Compliance Enforcement Authority's settlement procedures, provided, that (i) the Compliance Enforcement Authority may decline to engage in or continue settlement negotiations after a Possible Violation or Alleged Violation becomes a Confirmed Violation, and (ii) the Compliance Enforcement Authority, the Registered Entity or any other Participant may terminate settlement negotiations at any time.

1.9 Remedial Action Directives

1.9.1 Initiation of Remedial Action Directive Hearing

(a) Staff may issue a Remedial Action Directive to a Registered Entity at any time, including during any proceeding related to an Alleged Violation of a Reliability Standard. The Remedial Action Directive shall be delivered to the Registered Entity in accordance with Section 7.0 of the NERC Compliance Monitoring and Enforcement Program. The Compliance Enforcement Authority will notify NERC within two (2) business days after its Staff issues a Remedial Action Directive.

(b) The Registered Entity may contest the Remedial Action Directive by filing a written notice with the Clerk of the Compliance Enforcement Authority that states that the Registered Entity contests the Remedial Action Directive and that the Registered Entity requests a Remedial Action Directive hearing. The Registered Entity shall attach a copy of the Remedial Action Directive to its written notice. The Registered Entity must provide such notice within two (2) business days following the date of actual receipt (as defined in Section 7.0 of the NERC Compliance Monitoring and Enforcement Program) of the Remedial Action Directive. If the

Registered Entity does not give written notice to the Compliance Enforcement Authority within the required time period, the Registered Entity shall be deemed to have waived its right to contest the Remedial Action Directive.

(c) The Clerk shall assign a docket number, and issue a notice of hearing that sets forth the date, time and place at which the hearing will convene.

1.9.2 Remedial Action Directive Hearing Procedure

(a) Hearings to address Remedial Action Directives shall be conducted only under the expedited hearing process set forth in this Section 1.9.2. The general hearing procedures described in Sections 1.4 to 1.7 are applicable to the Remedial Action Directive hearing unless the context of a provision is inconsistent with or otherwise renders it inapplicable to the procedures set forth in this Section.

(b) The Remedial Action Directive hearing shall be presided over by a Hearing Officer and will be conducted according to the following guidelines:

(1) The Hearing Officer or the Hearing Body will hold a prehearing conference within two (2) business days after receipt of the Registered Entity's request for a hearing.

(2) A Testimonial Hearing will be conducted on the matter, in person or by teleconference, within seven (7) business days after the prehearing conference.

(3) At the Testimonial Hearing, Staff shall present oral witness testimony and evidence to show why the Remedial Action Directive should be complied with, and the Registered Entity shall present oral witness testimony and evidence to show why the Remedial Action Directive is not necessary or should be modified. All witness testimony shall be rendered under oath.

(4) At the Testimonial Hearing, the Participants shall have the opportunity to make opening statements. In addition, the Participants shall have the opportunity to make closing arguments, and Staff shall have the opportunity to make a rebuttal to the Registered Entity's closing argument.

(5) The Participants may file initial briefs and reply briefs, and/or draft opinions, on an expedited schedule set by the Hearing Officer or the Hearing Body. Oral argument shall not be held.

(c) The Hearing Body shall issue a summary written decision within ten (10) days following submission of the last brief, stating whether the Registered Entity shall or shall not be required to comply with the Remedial Action Directive and identifying any modifications to the Remedial Action Directive that the Hearing Body finds appropriate. Upon issuance of the summary written decision, the Registered Entity is required to comply with the Remedial Action Directive as specified in the summary written decision.

(d) Within thirty (30) days following issuance of its summary written decision, the Hearing Body shall issue a full written decision. The written decision shall state the conclusions of the

Hearing Body with respect to the Remedial Action Directive, and shall explain the reasons for the Hearing Body's conclusions.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation

Compliance Monitoring and Enforcement Program

APPENDIX 4C TO THE RULES OF PROCEDURE

Effective: TBD

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ATTACHMENT 1 – PROCESS FOR NON-SUBMITTAL OF REQUESTED DATA

ATTACHMENT 2 – COMPLIANCE ENFORCEMENT AUTHORITY HEARING PROCEDURE

COMPLIANCE MONITORING AND ENFORCEMENT PROGRAM

1.0 INTRODUCTION

This Compliance Monitoring and Enforcement Program ("Compliance Program") is the program to be used by the North American Electric Reliability Corporation ("NERC") and the Regional Entities to monitor, assess, and enforce compliance with Reliability Standards within the United States. Compliance Monitoring and Enforcement Programs also will be implemented in Canada consistent with Canadian laws and agreements.

1.1 Definitions

Capitalized terms used in this Compliance Program shall have the meanings set forth in Appendix 2 of the NERC Rules of Procedure. ~~For convenience of reference, defined terms frequently used in this Appendix are also set forth below:~~

~~Alleged Violation: A Possible Violation for which the Compliance Enforcement Authority has determined, based on an assessment of the facts and circumstances surrounding the Possible Violation, that evidence exists to indicate a Registered Entity has violated a Reliability Standard.~~

~~Annual Audit Plan: A plan developed annually by the Compliance Enforcement Authority that includes the Reliability Standards and Registered Entities to be audited and the schedule of Compliance Audits for the calendar year.~~

~~Applicable Governmental Authority: The Federal Energy Regulatory Commission ("FERC") within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability in Canada and Mexico.~~

~~Complaint: An allegation that a Registered Entity violated a Reliability Standard.~~

~~Compliance Audit: A systematic, objective review and examination of records and activities to determine whether a Registered Entity meets the Requirements of applicable Reliability Standards.~~

~~Compliance Audit Participants: Registered Entities scheduled to be audited and the audit team members.~~

~~Compliance Enforcement Authority: NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

~~Compliance Exception: A noncompliance that is addressed in Section 3A.0 of Appendix 4C, and is not pursued through an enforcement action under Section 5.0 of Appendix 4C by a Compliance Enforcement Authority.~~

~~**1.1.89** Compliance Investigation: A comprehensive investigation, which may include an on-site visit with interviews of the appropriate personnel, to determine if a violation of a Reliability Standard has occurred.**1.1.9**~~

~~**1.1.10** Confirmed Violation: An Alleged Violation for which (1) the Registered Entity has accepted or not contested the Notice of Alleged Violation and Proposed Penalty or Sanction or other notification of the Alleged Violation, or (2) there has been the issuance of a final order from NERC or a Regional Entity Hearing Body finding a violation, Penalty or sanction, or (3) the period for requesting a hearing or an appeal has expired, or (4) the Registered Entity has executed a settlement agreement pursuant to Section 5.6.~~

~~**1.1.1011** End Date: The last date of the period to be covered in a Compliance Audit.~~

~~**1.1.1112** Exception Report: Information provided to the Compliance Enforcement Authority by a Registered Entity indicating that a violation of a Reliability Standard has occurred (e.g., a System Operating Limit has been exceeded) or enabling the Compliance Enforcement Authority to ascertain the Registered Entity's compliance.~~

~~**1.1.13** Find, Fix, Track, and Report: A streamlined process, addressed in Section 3A.0 of Appendix 4C, to resolve lesser-risk, remediated Possible Violations that are not assessed a financial penalty.~~

~~**1.1.14** Inherent Risk Assessment ("IRA"): A review by the Compliance Enforcement Authority of potential risks posed by an individual Registered Entity to the reliability of the Bulk Power System. An IRA considers factors such as, but not limited to, assets, system, geography, interconnectivity, prior compliance history, and factors unique to the Registered Entity. The results of an entity-specific IRA may result in the scope of compliance monitoring for a particular Registered Entity to include more, fewer, or different Reliability Standards than those contained in the annual Implementation Plans.~~

~~**1.1.15** Internal Control Evaluation: A review by the Compliance Enforcement Authority of a Registered Entity's internal controls. The ICE may further refine the compliance oversight plan, including the scope of an audit, the type and application of compliance monitoring tools, the depth and breadth of a particular area of review, or determine whether an audit is necessary if the Registered Entity demonstrates effective internal controls.~~

~~**1.1.162** ISO/RTO: An independent transmission system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.~~

~~**1.1.173** Mitigating Activities: Actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a Mitigation Plan.~~

~~**1.1.184** Mitigation Plan: An action plan developed by the Registered Entity to (1) correct a violation of a Reliability Standard and (2) prevent re-occurrence of the violation.~~

~~**1.1.195** NERC Compliance Registry: A list, maintained by NERC pursuant to Section 500 of the NERC Rules of Procedure and Appendix 5B, the NERC *Statement of Compliance Registry Criteria*, of the owners, operators and users of the Bulk Power System, and the entities registered as their designees, that perform one or more functions in support of reliability of the Bulk Power System and are required to comply with one or more Requirements of Reliability Standards.~~

~~**1.1.1620** NERC Compliance Monitoring and Enforcement Program Implementation Plan or NERC Implementation Plan: The annual NERC Compliance Monitoring and Enforcement~~

~~Program Implementation Plan that specifies the Reliability Standards that are subject to reporting~~identifies the risk elements to prioritize risks to the reliability of the Bulk Power System. These risk elements and related NERC Reliability Standards Requirements become inputs for Regional Entities in developing their Regional Implementation Plans and the compliance oversight plan for individual ~~by Registered Entities to the Compliance Enforcement Authority in order to verify compliance and identifies the appropriate monitoring procedures and reporting schedules for each such Reliability Standard.~~ The NERC Implementation Plan may be updated as needed.

~~**1.1.17**~~**21** ~~Notice of Alleged Violation and Proposed Penalty or Sanction: A notice issued by the Compliance Enforcement Authority to a Registered Entity pursuant to Section 5.3.~~

~~**1.1.18**~~**22** ~~Notice of Completion of Enforcement Action: A notice issued by the Compliance Enforcement Authority to a Registered Entity, pursuant to Section 5.10, stating than an enforcement action is closed.~~

~~**1.1.19**~~**23** ~~Notice of Confirmed Violation: A notice issued by the Compliance Enforcement Authority to a Registered Entity confirming the violation of one or more Reliability Standards.~~

~~**1.1.20**~~**24** ~~Notice of Penalty: A notice prepared by NERC and filed with FERC, following approval by NERC of a Notice or other notification of Confirmed Violation or a settlement agreement, stating the Penalty or sanction imposed or agreed to for the Confirmed Violation or as part of the settlement.~~

~~**1.1.21**~~**25** ~~Notice of Possible Violation: A notice issued by the Compliance Enforcement Authority to a Registered Entity that (1) states a Possible Violation has been identified, (2) provides a brief description of the Possible Violation, including the Reliability Standard Requirement(s) and the date(s) involved, and (3) instructs the Registered Entity to retain and preserve all data and records relating to the Possible Violation.~~

~~**1.1.22**~~**26** ~~Periodic Data Submittals: Modeling, studies, analyses, documents, procedures, methodologies, operating data, process information or other information to demonstrate compliance with Reliability Standards and provided by Registered Entities to the Compliance Enforcement Authority on a time frame required by a Reliability Standard or an ad hoc basis.~~

~~**1.1.23**~~**27** ~~Possible Violation: The identification, by the Compliance Enforcement Authority, of a possible failure by a Registered Entity to comply with a Reliability Standard that is applicable to the Registered Entity.~~

~~**1.1.24**~~**28** ~~Preliminary Screen: An initial evaluation of evidence indicating potential noncompliance with a Reliability Standard has occurred or is occurring, conducted by the Compliance Enforcement Authority for the purpose of determining whether a Possible Violation exists, and consisting of an evaluation of whether (1) the entity allegedly involved in the potential noncompliance is registered, (2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to a reliability function for which the entity is registered, and (3) if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation which is currently being processed.~~

~~**1.1.2529** Regional Implementation Plan: An annual Regional Entity plan, submitted by on or about October 1 of each year to NERC for approval that, in accordance with NERC Rule of Procedure Section 401.6 and the NERC Compliance Monitoring and Enforcement Program Implementation Plan, includes (1) details on Regional Risk Assessment processes and results; (2) Reliability Standards and Requirements associated with Regional Risk Assessment results; identifies (1) all Reliability Standards identified by NERC to be actively monitored during each year, (2) other Reliability Standards proposed for active monitoring by the Regional Entity, (3) the methods to be used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria with each Reliability Standard;, and (4) the Regional Entity's Annual Audit Plan.~~

~~**1.1.2630** Registered Entity: An owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry.~~

~~**1.1.2731** Remedial Action Directive: An action (other than a Penalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a Registered Entity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.~~

~~**1.1.2832** Required Date: The date given a Registered Entity in a notice from the Compliance Enforcement Authority by which some action by the Registered Entity is required.~~

~~**1.1.2933** Self-Certification: An attestation by a Registered Entity that it is compliant or non-compliant with a Reliability Standard Requirement that is the subject of the Self-Certification, or that it does not own Facilities that are subject to the Reliability Standard Requirement, or that the Reliability Standard Requirement is not applicable to the Registered Entity.~~

~~**1.1.34** Self-Logging: A process by which Registered Entities found to be eligible by a Compliance Enforcement Authority, after a formal review of internal controls, record noncompliance on a log, in accordance with Section 3.5A of Appendix 4C, in lieu of individually self-reporting each possible noncompliance.~~

~~**1.1.3035** Self-Report: A report by a Registered Entity stating that the Registered Entity believes it has, or may have, violated a Reliability Standard.~~

~~**1.1.3136** Spot Check: A process in which the Compliance Enforcement Authority requests a Registered Entity to provide information (1) to support the Registered Entity's Self-Certification, Self-Report, or Periodic Data Submittal and to assess whether the Registered Entity complies with Reliability Standards, or (2) as a random check, or (3) in response to operating problems or system events.~~

2.0 IDENTIFICATION OF ORGANIZATIONS RESPONSIBLE FOR COMPLYING WITH RELIABILITY STANDARDS

NERC shall register the organizations responsible for complying with Reliability Standards, in accordance with Section 500 of the NERC Rules of Procedure and Appendix 5B, *Statement of*

Compliance Registry Criteria. Organizations are responsible to register and to comply with Reliability Standards if they are owners, operators, and users of the Bulk Power System, perform a function listed in the functional types identified in Section II of Appendix 5B, and are material to the Reliable Operation of the Bulk Power System as defined by the criteria and notes in Appendix 5B. Regional Entities shall (i) develop and provide to NERC information to assist NERC to register organizations responsible for complying with Reliability Standards, and (ii) in the event of a Registration appeal to NERC or an Applicable Governmental Authority, provide information requested by NERC concerning how the Registered Entity meets the Registration criteria or is otherwise material to the reliability of the Bulk Power System.

NERC shall notify organizations of their inclusion on the NERC Compliance Registry and shall maintain the NERC Compliance Registry on its web site. NERC shall inform each Registered Entity at the time of Registration of the Reliability Standards that are applicable to reliability functions for which the Registered Entity is registered. Each Registered Entity shall inform NERC or the applicable Regional Entity promptly of changes to the Registered Entity's Registration information including planned or completed changes in ownership of Bulk Power System Facilities, Registration status, address and other contact information, and name of designated compliance contact. NERC will provide FERC and Applicable Governmental Authorities monthly updates to the NERC Compliance Registry.

NERC and each Regional Entity will designate a contact person(s) and require each Registered Entity to designate a contact person(s) responsible for sending and receiving all necessary information and communications concerning compliance matters. NERC and the applicable Regional Entity will designate where Registered Entities are to send information, data, Mitigation Plans, or any other compliance-related correspondence.

NERC shall maintain on its website a current listing of Reliability Standards that are applicable to all Registered Entities.

As provided for herein, during the course of compliance monitoring and enforcement activities relating to U.S. entities, NERC may obtain information that it will provide to FERC and, if the information pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority. Any such provision of information to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure.

3.0 COMPLIANCE MONITORING PROCESSES

NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify risk elements and related NERC Reliability Standards and Requirements to be considered in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan (Implementation Plan). NERC identifies the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. NERC uses these risk elements to identify and prioritize continent-wide risks to the reliability of the ~~BPS~~Bulk Power System. These identified risks represent the focus for oversight activities in the

upcoming year, and become inputs for developing oversight plans for individual Registered Entities.

The Compliance Enforcement Authority will monitor Registered Entities' compliance with Reliability Standards using the compliance monitoring processes described in this Section. A Compliance Enforcement Authority will determine the type and frequency of application of the compliance monitoring tools appropriate for a particular Registered Entity based on the Registered Entity's specific risks to the reliability of the Bulk Power System.

If a compliance monitoring process described in this Section reveals a potential noncompliance with a Reliability Standard, the Compliance Enforcement Authority will conduct a Preliminary Screen of the potential noncompliance in accordance with Section 3.8. In addition, if the Compliance Enforcement Authority obtains evidence or information of a potential noncompliance with a Reliability Standard through any other means, including but not limited to an Exception Report or other report of noncompliance that a Registered Entity is required to submit in accordance with the terms of a Reliability Standard, the Compliance Enforcement Authority will conduct a Preliminary Screen of the information in accordance with Section 3.8. If the Preliminary Screen results in an affirmative determination with respect to the Preliminary Screen criteria, a Possible Violation exists and the Compliance Enforcement Authority will proceed in accordance with Section 5.0, Enforcement Actions ~~unless an alternative enforcement process is used, in accordance with Section 3A.0~~except as otherwise authorized in these Rules of Procedure.

Registered Entities found in violation of a Reliability Standard will be required to mitigate the violation regardless of any enforcement actions taken.

The compliance monitoring processes in this Section require timely information, reports and data from Registered Entities to effectively monitor compliance with Reliability Standards. The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies of Documents, data and information to be made and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. If Documents, data, information or other reports to determine compliance requested from a Registered Entity are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel.

Any report or other submission of information by a Registered Entity required by the Compliance Program shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity. Electronic signatures are permitted in accordance with processes established by NERC and the Regional Entity. NERC or the Compliance Enforcement Authority may require the signer to provide a statement of the basis of his or her authority to sign on behalf of the Registered Entity.

3.1 Compliance Audits

All Registered Entities are subject to audit for compliance with all Reliability Standards applicable to the functions for which the Registered Entity is registered. Compliance Audits are conducted on the Registered Entity's site to the extent required by NERC Rule of Procedure 403.11.2. Compliance Audit processes for Compliance Audits conducted in the United States shall be based on professional auditing standards recognized in the U.S., which may include for example Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards and standards sanctioned by the Institute of Internal Auditors. Compliance Audit processes for Compliance Audits conducted outside the U.S. may be based on Canadian or other international standards. All Compliance Audits shall be conducted in accordance with audit guides established for the Reliability Standards included in the Compliance Audit, consistent with accepted auditing guidelines as approved by NERC. The audit guides will be posted on NERC's website.

3.1.1 Compliance Audit Process Steps

The process steps for a Compliance Audit are as follows:

- The Compliance Enforcement Authority posts the Annual Audit Plan (developed in coordination with NERC). The Compliance Enforcement Authority provides additional information to the Compliance Audit Participants, including Compliance Audit materials, coordinating agendas and changes to the Compliance Audit schedule as required. NERC or the Regional Entity provides the Compliance Audit schedules to FERC and to any other Applicable Governmental Authority based upon the agreements in place with the other Applicable Governmental Authority.

- At least ninety (90) days prior to commencement of a regularly scheduled Compliance Audit, the Compliance Enforcement Authority notifies the Registered Entity of the Compliance Audit and the Reliability Standards to be evaluated, identifies the Compliance Audit team members and their recent employment history, and requests data, including a completed NERC pre-Compliance Audit questionnaire. If the Compliance Audit team members change from the time of the original notification, the Compliance Enforcement Authority will promptly notify the Registered Entity of the change and will allow time for the Registered Entity to object to the new Compliance Audit team member(s) (see Section 3.1.5.4).

- The Registered Entity provides to the Compliance Enforcement Authority the required information in the format and by the Required Date specified in the request.

- The Compliance Audit team reviews the submitted information for conformance with the Requirements of the Reliability Standards.

- The Compliance Audit team conducts an exit briefing with the Registered Entity, provides for a review of the Compliance Audit report with the Registered Entity before it is finalized, and completes a Compliance Audit report in accordance with Section 3.1.6.

- If the Compliance Audit Team identifies evidence of a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

3.1.2 Compliance Enforcement Authority Annual Audit Plan and Schedule

The Compliance Enforcement Authority shall develop an Annual Audit Plan. The Annual Audit Plan of Regional Entities will be included in the Regional Implementation Plans submitted to NERC for review and approval (see Section 4.2). NERC or the Regional Entity provides the Annual Audit Plans to FERC and to any other Applicable Governmental Authority consistent with the agreements in place with the Applicable Governmental Authority.

Prior to October 1 of the year preceding the year covered by the Annual Audit Plan, the Compliance Enforcement Authority shall notify Registered Entities subject to Compliance Audits during the upcoming year of the Compliance Audit schedule. The Compliance Enforcement Authority will give due consideration to any schedule changes requested by Registered Entities for reasonable cause.

Revisions and additions to a Regional Entity Annual Audit Plan shall be communicated to and approved by NERC, and shall be communicated to the Registered Entity in a timely manner (normally sixty (60) days in advance) of changes or revisions to scheduled Compliance Audit dates.

3.1.3 Frequency of Compliance Audits

The Compliance Enforcement Authority will perform comprehensive Compliance Audits as required by the NERC Rules of Procedure and based on criteria established by NERC. In addition to scheduled Compliance Audits, the Compliance Enforcement Authority (i) may initiate an unscheduled Compliance Audit of any Registered Entity at any time if the Compliance Enforcement Authority reasonably determines it to be necessary to ensure the Registered Entity's compliance with Reliability Standards, and (ii) shall initiate an unscheduled Compliance Audit if directed by FERC. The Compliance Enforcement Authority shall notify NERC and FERC prior to or on the same date it notifies the Registered Entity that an unscheduled Compliance Audit is being initiated. If NERC initiates the unscheduled Compliance Audit, it shall notify the appropriate Regional Entity or Entities. The Compliance Enforcement Authority shall provide at least ten (10) business days advance notice to the Registered Entity that an unscheduled Compliance Audit is being initiated, which notice shall include identification of the members of the Compliance Audit team.

3.1.4 Scope of Compliance Audits

3.1.4.1 Reliability Standards

A Compliance Audit shall include those Reliability Standards applicable to the Registered Entity that are ~~identified in the NERC Implementation Plan for the current year~~determined through the NERC approved risk-based processes described herein, and may include other Reliability Standards applicable to the Registered Entity whether or not they are identified in the Regional Entity's Regional Implementation Plan for the current year.

Regional Entities will tailor the final scope of any Compliance Audit based on the results of the Registered Entity's Inherent Risk Assessment and, if applicable, taking into consideration the results of an Internal Controls Evaluation. ~~a Registered Entity's inherent risk and on the evaluation, if applicable, of the Registered Entity's internal controls pertinent to the applicable Reliability Standards.~~ Except as otherwise required in the Rules of Procedure, the Compliance Enforcement Authority may use any process herein, in addition to, or in lieu of a Compliance Audit to monitor compliance with Reliability Standards.

3.1.4.2 Period Covered

The Registered Entity's data and information must show compliance with the Reliability Standards that are the subject of the Compliance Audit for the entire period covered by the Compliance Audit. The Compliance Enforcement Authority will indicate the beginning and End Date of the audit period in its notice of the Compliance Audit. The audit period begins the day after the End Date of the prior Compliance Audit by the Compliance Enforcement Authority (or the later of June 18, 2007 or the date the Registered Entity became subject to Reliability Standards if the Registered Entity has not previously been subject to a Compliance Audit). The audit period will not begin prior to the End Date of the previous Compliance Audit. The Compliance Enforcement Authority may modify the beginning date of the audit period for any given Reliability Standard Requirement based on an intervening compliance monitoring process. The End Date should be a specified date prior to the scheduled start of the Compliance Audit, such as the date of the notification issued to the Registered Entity pursuant to Section 3.1.1 or the date that is thirty (30) days following the date of the notification.

The Registered Entity will be expected to demonstrate compliance for the entire period described above. If a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard. However, in such cases, the Compliance Enforcement Authority will require the Registered Entity to demonstrate compliance through other means. In addition, if the Compliance Audit team discovers a potential noncompliance occurring subsequent to the End Date, the potential noncompliance will be subject to a Preliminary Screen pursuant to Section 3.8.

3.1.4.3 Review of Mitigating Activities

The Compliance Audit may include a review of any Mitigating Activities which the Registered Entity has not yet completed, for the purpose of determining whether the Registered Entity is making adequate progress towards completion of the Mitigating Activities.

3.1.5 Conduct of Compliance Audits

3.1.5.1 Composition of Compliance Audit Teams

The Compliance Audit team shall be comprised of members whom the Compliance Enforcement Authority has determined have the requisite knowledge, training and skills to conduct the Compliance Audit. The Compliance Audit team may include (i) contractors and industry subject matter experts, (ii) NERC staff members (which may include contractors to NERC), (iii) compliance staff members of other Regional Entities, and (iv) representatives of FERC and other Applicable Governmental Authorities so long as the Registered Entity is subject to the Applicable Governmental Authority's reliability jurisdiction. The Compliance Audit team leader shall be a staff member from the Compliance Enforcement Authority and is responsible for the conduct of the Compliance Audit and preparation of the Compliance Audit report.

3.1.5.2 Requirements for Compliance Audit Team Members

Each Compliance Audit team member must:

- Be free of conflicts of interests in accordance with the Compliance Enforcement Authority policies. Employees or contractors of the Registered Entity being audited shall not be allowed to participate as auditors in the Compliance Audit of the Registered Entity.

- Comply with the NERC Antitrust Compliance Guidelines and shall have either signed appropriate confidentiality agreements or acknowledgments that the confidentiality agreement signed by the Compliance Enforcement Authority is applicable.

- Successfully complete all NERC or NERC-approved Regional Entity auditor training applicable to the Compliance Audit.

- Prior to the Compliance Audit, the Compliance Enforcement Authority shall provide confirmation to the Registered Entity that all Compliance Audit team members have executed confidentiality agreements or acknowledgements.

3.1.5.3 Compliance Audit Observers and Other Attendees

In any Regional Entity Compliance Audit of a Registered Entity, in addition to the Compliance Audit team members, the following may participate as observers: (i) NERC Staff (which may include contractors to NERC); (ii) other members of the Regional Entity's Compliance Staff; (iii) with the permission of the Regional Entity, Compliance Staff members of other Regional Entities; and (iv) representatives of FERC and of other Applicable Governmental Authorities so long as the Registered Entity is subject to the Applicable Governmental Authority's reliability jurisdiction. Any members of NERC staff, Regional Entity Compliance Staff, or Compliance Staffs of other Regional Entities or representatives of FERC or other Applicable Governmental

Authorities who are not Compliance Audit team members identified pursuant to Section 3.1.1 are observers.

In addition, at the request of the Registered Entity being audited, the Regional Entity may allow attendance at the Compliance Audit by: (1) representatives of corporate affiliates of the Registered Entity being audited that are Registered Entities or that provide compliance services, support or oversight to the Registered Entity being audited, and (2) representatives of Registered Entities whose compliance activities are conducted by the Registered Entity being audited or by the same corporate entity that conducts the compliance activities of the Registered Entity being audited (e.g., representatives of other members of a Joint Registration Organization or of participants in a Coordinated Functional Registration pursuant to Section 500 of the Rules of Procedure). Each such additional attendee must execute a confidentiality agreement approved by the Regional Entity.

Compliance Audit observers and attendees are not Compliance Audit team members and do not participate in conducting the Compliance Audit or in making Compliance Audit findings and determinations.

The Compliance Audit team leader or other staff of the Regional Entity conducting the Compliance Audit will communicate in advance with any observers or other attendees to ensure there are no undue disruptions to the Compliance Audit, such as space limitations, no conflicts of interest, and no other considerations that in the judgment of the Compliance Audit team leader may be detrimental to the conduct and quality of the Compliance Audit. If the Compliance Audit team leader identifies any such issues, he/she shall work with the proposed observers or attendees to facilitate observation in a less disruptive manner; or, alternatively, the Regional Entity Compliance staff will work with the proposed observers or attendees to schedule their participation in, observation of, or attendance at a different Compliance Audit in which such issues are not presented.

3.1.5.4 Registered Entity Objections to Compliance Audit Team

A Registered Entity subject to a Compliance Audit may object to any member of the Compliance Audit team on grounds of a conflict of interest or the existence of other circumstances that could interfere with the team member's impartial performance of his or her duties. Any such objections must be provided in writing to the Compliance Enforcement Authority no later than fifteen (15) days prior to the start of on-site Compliance Audit work. This fifteen (15) day requirement shall not apply where a Compliance Audit team member has been appointed less than twenty (20) days prior to the start of on-site Compliance Audit work, in which case the Registered Entity must provide any objections to the Compliance Enforcement Authority within five (5) business days after receiving notice of the appointment of the Compliance Audit team member.

In the case of an unscheduled Compliance Audit pursuant to Section 3.1.3, the Registered Entity must provide any objections to the Compliance Enforcement Authority at least five (5) business days prior to the start of on-site Compliance Audit work for the unscheduled Compliance Audit.

The Compliance Enforcement Authority will make a final determination on whether the member will participate in the Compliance Audit of the Registered Entity. Nothing in Section 3.1 shall be read to limit the participation of NERC staff in the Compliance Audit or to limit the participation of FERC staff in a Compliance Audit of a Registered Entity, or involving a portion of the Bulk Power System, over which FERC has jurisdiction.

3.1.6 Compliance Audit Reports

The Compliance Audit team shall develop a draft Compliance Audit report that shall include a description of the objective, scope, and methodology of the Compliance Audit; identify any evidence of potential noncompliance with Reliability Standards by the Registered Entity found by the Compliance Audit team; identify any Remedial Action Directives, Mitigation Plans or other Mitigating Activities which have been completed or pending in the year of the Compliance Audit; and identify if any Confidential Information has been redacted. The report may also state areas of concern and recommendations identified by the Compliance Audit team. The draft report will be provided to the Registered Entity for comment.

The Compliance Audit team considers corrections based on comments of the Registered Entity, finalizes the Compliance Audit report, and provides the Registered Entity with a copy of the final report on or before the date the final report is provided to NERC. The Compliance Enforcement Authority provides the final report to NERC, which in turn provides the report to FERC if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which FERC has jurisdiction and/or to another Applicable Governmental Authority if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which the other Applicable Governmental Authority has jurisdiction. The provision of the final Compliance Audit report to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure. Work papers and other documentation associated with the Compliance Audit shall be maintained by the Compliance Enforcement Authority in accordance with NERC or Regional Entity requirements.

NERC will not publicly post the final Compliance Audit report for at least five (5) business days following receipt. If the Compliance Audit report identifies any Possible Violations of one or more Reliability Standards, the final Compliance Audit report, or pertinent part thereof identifying the Possible Violations, shall not be released to the public by NERC until (i) the Possible Violation is dismissed prior to becoming a Confirmed Violation, or (ii) NERC submits a Notice of Penalty to FERC or other Applicable Governmental Authority, or (iii) the Registered Entity executes a settlement agreement with the Compliance Enforcement Authority pursuant to Section 5.6.

Information deemed by a Compliance Enforcement Authority or the Registered Entity as Critical Energy Infrastructure Information or Confidential Information shall be redacted from any public reports.

3.2 Self-Certifications

The Compliance Enforcement Authority may require Registered Entities to self-certify their compliance with Reliability Standards.

3.2.1 Self-Certification Process Steps

The process steps for the Self-Certification process are as follows:

- The Compliance Enforcement Authority posts and updates the reporting schedule containing the applicable reporting periods and informs Registered Entities. The Compliance Enforcement Authority and NERC will ensure that the appropriate Reliability Standards, compliance procedures, and required submittal forms for the Reliability Standards being evaluated are maintained and available.

- The Compliance Enforcement Authority requests the Registered Entity to make a Self-Certification within the advance notice period specified by the Reliability Standard. If the Reliability Standard does not specify the advance notice period, this request will be issued in a timely manner (normally thirty (30) days advance notice).

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the form and manner, and by the Required Date, specified by the Compliance Enforcement Authority. The Self-Certification response may state that (i) the Registered Entity is in compliance with the Reliability Standard Requirement, (ii) the Registered Entity is not in compliance with the Reliability Standard Requirement, (iii) the Registered Entity does not own Facilities that are subject to the Reliability Standard Requirement, or (iv) the Reliability Standard requirement is not applicable to the Registered Entity.

- At a minimum, the Compliance Enforcement Authority reviews Self-Certifications of non-compliance and Self-Certifications in which the Registered Entity has responded that it does not own Facilities that are subject to the Reliability Standard Requirement or that the Reliability Standard Requirement is not applicable to the Registered Entity and the Compliance Enforcement Authority may request additional data and/or information if necessary.

- If the Compliance Enforcement Authority's review of the Self-Certification indicates a potential noncompliance with a Reliability Standard by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

Receipt of a Self-Certification by the Compliance Enforcement Authority shall not be construed as a finding by the Compliance Enforcement Authority that the Registered Entity is compliant with, not compliant with, subject to, or not subject to, the Reliability Standard Requirement.

3.3 Spot Checks

Spot Checks will be conducted by the Compliance Enforcement Authority. Spot Checks may be initiated at the discretion of the Compliance Enforcement Authority or as directed by NERC at any time to verify or confirm Self-Certifications, Self-Reports, and Periodic Data Submittals. Spot Checks may also be random or may be initiated in response to events, as described in the Reliability Standards, or to operating problems, or system events.

3.3.1 Spot Check Process Steps

The process steps for Spot Checking are as follows:

- The Compliance Enforcement Authority shall issue a notification letter to the Registered Entity that a Spot Check will be performed, the reason for the Spot Check, and the scope of the Spot Check including the Reliability Standard Requirements that will be covered, in accordance with the advance notice period specified by the Reliability Standard. If the Reliability Standard Requirement does not specify an advance notice period, any information submittal request made by the Compliance Enforcement Authority will allow at least twenty (20) days for the Registered Entity to submit the information or make it available for review.

- The Compliance Enforcement Authority, as part of the notification package, shall provide the Registered Entity with the names and employment histories of the persons who will be conducting the Spot Check. The Compliance Enforcement Authority shall provide confirmation to the Registered Entity that the members of the Spot Check team have executed confidentiality agreements or acknowledgements. The Registered Entity may object to inclusion of any individual on the Spot Check team on the grounds specified in Section 3.1.5.4. Any such objections must be submitted to the Compliance Enforcement Authority by the later of (i) five (5) business days before the information being requested by the Compliance Enforcement Authority is submitted and (ii) five (5) business days after the Registered Entity is notified of the persons on the Spot Check team. Nothing in Section 3.1 shall be read to limit the participation of NERC staff in a Spot Check or to limit the participation of FERC staff in a Spot Check of a Registered Entity, or involving a portion of the Bulk Power System, over which FERC has jurisdiction.

- The Spot Check may require submission of data, documentation, and information and an on-site review.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date specified in the request.

- The Spot Check Team conducts a review of the information submitted to determine compliance with the Reliability Standards Requirements and may request additional data and/or information if necessary.

- If the Spot Check team's review of the information submitted indicates a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen pursuant to Section 3.8.

- The Spot Check team prepares a draft Spot Check report and provides the Registered Entity ten (10) business days to comment on the draft report.

- The Spot Check team considers any corrections based on the Registered Entity's comments, finalizes the Spot Check report and provides it to the Registered Entity and to NERC.

- If the Compliance Enforcement Authority is a Regional Entity, the Regional Entity provides the final report to NERC. NERC provides the report to FERC if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which FERC has jurisdiction and/or to another Applicable Governmental Authority if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which the other Applicable Governmental Authority has jurisdiction. The provision of the report to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure.

- The report will not be publicly posted, or otherwise made publicly available, by the Regional Entity or by NERC.

3.4 Compliance Investigations

A Compliance Investigation may be initiated at any time by the Compliance Enforcement Authority or NERC in response to a system disturbance, Complaint, or any potential noncompliance with a Reliability Standard identified by any other means.

Compliance Investigations will generally be led by the Regional Entity's staff. NERC reserves the right to assume the leadership of a Compliance Investigation.[1] The Regional Entity shall not be entitled to appeal NERC's decision to lead a Compliance Investigation.

Compliance Investigations are confidential, unless FERC directs that a Compliance Investigation should be public or that certain information obtained in the Compliance Investigation should be publicly disclosed. Confirmed Violations resulting from a Compliance Investigation will be made public.

FERC or another Applicable Governmental Authority may initiate an investigation at any time in response to a system disturbance, Complaint, or potential noncompliance with a Reliability Standard identified by any other means, or for any other purpose authorized by law. Investigations initiated by FERC or another Applicable Governmental Authority shall be governed by and conducted pursuant to the statutory authority and rules of the Applicable Governmental Authority and not the procedures set forth herein. If an Applicable Governmental Authority other than FERC initiates an investigation of a U.S.-related matter, NERC shall provide notice to FERC of the investigation prior to disclosure of any non-public U.S.-related compliance information regarding the matter to be investigated to the other Applicable Governmental Authority. NERC's notice to FERC shall identify the other Applicable Governmental Authority, shall describe the nature of the proposed disclosures to the other Applicable Governmental Authority, and shall state the procedures NERC will utilize in

[1]Examples of situations in which NERC may decide to lead a Compliance Investigation include: (i) to assure consistency in investigative processes, (ii) to coordinate Compliance Investigations into matters that may cross Regional Entity boundaries, (iii) where the potential noncompliance is related to the Regional Entity or one of its affiliates, divisions, committees or subordinate structures, or (iv) where the Regional Entity determines it cannot conduct the Compliance Investigation.

connection with the Compliance Investigation to ensure compliance with the requirements of 18 C.F.R. §39.7(b)(4) concerning nondisclosure of violations and Alleged Violations.

If FERC initiates an investigation of a non-U.S.-related matter, NERC shall provide notice of the investigation to the Applicable Governmental Authority having jurisdiction over the Registered Entity or the portion of the Bulk Power System that is the subject of the investigation prior to disclosure to FERC of any non-public non-U.S.-related compliance information regarding the matter to be investigated. NERC's notice to the other Applicable Governmental Authority shall describe the nature of the proposed disclosures to FERC and shall state the procedures NERC will utilize in connection with the investigation to ensure compliance with regulations of the other Applicable Governmental Authority or other law of the applicable jurisdiction concerning disclosure of non-public compliance information.

3.4.1 Compliance Investigation Process Steps

The process steps for a Compliance Investigation are as follows:

- The Compliance Enforcement Authority becomes aware of circumstances indicating a Reliability Standard may have been or is being violated and determines whether a Compliance Investigation is warranted. Within three (3) business days of the decision to initiate a Compliance Investigation, the Compliance Enforcement Authority: (i) notifies the Registered Entity of the initiation and initial scope of the Compliance Investigation, (ii) instructs the Registered Entity to preserve all records and information relevant to the Compliance Investigation, and (iii) provides a copy of the notice to NERC. The Compliance Investigation may be expanded beyond the initial scope based on information obtained by the Compliance Enforcement Authority after initiation of the Compliance Investigation.

- NERC assigns a NERC staff member to the Compliance Investigation as an observer or team member and to serve as a single point of contact for communications with NERC, and notifies the Registered Entity as to whether the NERC staff member is acting as an observer or as a team member. Within three (3) business days after NERC receives notice of the decision to initiate a Compliance Investigation, NERC will notify FERC and each other Applicable Governmental Authority having jurisdiction over a Registered Entity or a portion of the Bulk Power System to which the Compliance Investigation relates. Any such notice to FERC or to another Applicable Governmental Authority will be provided in accordance with Section 8.0, Reporting and Disclosure.

  The Compliance Enforcement Authority requests data or documentation and provides a list of individuals on the Compliance Investigation team and their recent employment history. Within ten (10) business days of receiving the notification of a Compliance Investigation, a Registered Entity subject to a Compliance Investigation may object to any individual member of the Compliance Investigation team on grounds of a conflict of interest or the existence of other circumstances that could interfere with the team member's impartial performance of his or her duties; however, the Registered Entity may not object to participation by NERC, by FERC staff or by staff of another Applicable Governmental Authority having reliability jurisdiction over the Registered Entity in the Compliance Investigation. Such objections must be provided in writing to

the Compliance Enforcement Authority within such ten (10) business day period. The Compliance Enforcement Authority will make a final determination as to whether the individual will participate in the Compliance Investigation of the Registered Entity.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date as specified in the request. If information is not received in the time and format requested, the Compliance Enforcement Authority may initiate the steps in **Process for Non-Submittal of Requested Data in Attachment 1.**

- If necessary, the Compliance Investigation may include an on-site visit with interviews of the appropriate personnel and review of data.

- The Compliance Enforcement Authority may require the Registered Entity to (i) provide a verification under oath by an officer, employee, attorney or other authorized representative of the Registered Entity attesting to the accuracy, completeness and truth of the Registered Entity's responses to the Compliance Enforcement Authority's requests for information; and (ii) produce one or more officers, employees or other authorized representatives of the Registered Entity who are familiar with the matter(s) that are the subject of the Compliance Investigation, to be interviewed or to provide testimony under oath concerning such matters. The Compliance Enforcement Authority shall determine in each case (i) whether representatives of the Registered Entity shall be allowed to be present when an interview is taking place or testimony is being taken, and (ii) whether, and by what method, the interview or testimony shall be recorded; provided, that counsel for the person being interviewed or giving testimony may be present when the interview is being conducted or testimony is being taken (regardless of whether such counsel also represents the Registered Entity).

- The Compliance Enforcement Authority reviews information to determine compliance with the Reliability Standards. The Compliance Enforcement Authority may request additional data and/or information, if necessary.

- The Compliance Enforcement Authority completes the assessment of compliance with the Reliability Standard, which may include review of a Mitigation Plan or Mitigating Activities, and provides a report of the Compliance Investigation to NERC and the Registered Entity.

- If the Compliance Enforcement Authority, at any time during the Compliance Investigation, identifies a potential noncompliance with a Reliability Standard Requirement by a Registered Entity, the Compliance Enforcement Authority shall conduct a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

- If the Compliance Enforcement Authority determines that no violation occurred, it shall send the Registered Entity and NERC a notice that the Compliance Investigation has been completed. NERC will in turn notify FERC and, if the Compliance Investigation pertained to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, will also notify such other

Applicable Governmental Authority. Any such notice to FERC or to another Applicable Governmental Authority shall be provided in accordance with Section 8.0, Reporting and Disclosure.

3.5 Self-Reports

Self-Reports are encouraged at the time a Registered Entity becomes aware (i) that it has, or may have, violated a Reliability Standard, or (ii) the Violation Severity Level of a previously reported violation has changed. Self-Reports of a violation of a Reliability Standard are encouraged regardless of whether the Reliability Standard requires reporting on a pre-defined schedule in the Compliance Program or whether the violation is determined outside the pre-defined reporting schedule. If possible, and without delaying the Self-Report, a Self-Report may include the actions that have been taken or will be taken to resolve the violation.

3.5.1 Self-Report Process Steps

The process steps for Self-Reports are as follows:

- The Compliance Enforcement Authority posts the Self-Report submittal forms and ensures they are maintained and available.
- The Registered Entity provides the Self-Report information to the Compliance Enforcement Authority.
- The Compliance Enforcement Authority reviews the information to evaluate compliance with the Reliability Standards and may request that the Registered Entity provide clarification or additional data and/or information.
- The Compliance Enforcement Authority conducts a Preliminary Screen of the Self-Report information in accordance with Section 3.8.

3.5A Self-Logging

Registered Entities found by the Compliance Enforcement Authority to be eligible, after a formal review of internal controls, pursuant to procedures adopted by NERC and the Regional Entities and provided to Applicable Governmental Authorities, may be granted approval by the Compliance Enforcement Authority to log noncompliance for subsequent review in lieu of submitting a Self-Report. The log shall be limited to noncompliance posing a minimal risk to the reliability of the Bulk Power System unless otherwise authorized by an Applicable Governmental Authority. Approved Registered Entities shall maintain a log with a detailed description of the noncompliance, the risk assessment, and the mitigating activities completed or to be completed. There is a rebuttable presumption that noncompliance logged in this manner will be resolved as a Compliance Exception. The Compliance Enforcement Authority will periodically review the logs and will make the logs available for review, upon request, by NERC and Applicable Governmental Authorities.

3.6 Periodic Data Submittals

The Compliance Enforcement Authority requires Periodic Data Submittals in accordance with the schedule stated in the applicable Reliability Standard, or as established by the Compliance Enforcement Authority, or on an as-needed basis. The Compliance Enforcement Authority shall issue requests for Periodic Data Submittals to Registered Entities within at least the minimum advance notice period specified by the applicable Reliability Standard. If the Reliability Standard does not specify an advance notice period, the Compliance Enforcement Authority will normally issue this request with no less than twenty (20) days advance notice.

3.6.1 Periodic Data Submittals Process Steps

The process steps for Periodic Data Submittal are as follows:

- The Compliance Enforcement Authority posts the current data reporting schedule on its website and informs Registered Entities of changes and/or updates. The Compliance Enforcement Authority ensures that the required submittal forms for the Reliability Standards being evaluated are maintained and available.

- The Compliance Enforcement Authority makes a request for a Periodic Data Submittal.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date specified in the request.

- The Compliance Enforcement Authority reviews the data submittal to determine compliance with the Reliability Standards and may request additional data and/or information if necessary.

- If the Compliance Enforcement Authority's review of the data submittal indicates a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority performs a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

Receipt of a Periodic Data Submittal by the Compliance Enforcement Authority shall not be construed as a finding by the Compliance Enforcement Authority that the Registered Entity is compliant with, not compliant with, subject to, or not subject to, the Reliability Standard Requirement.

3.7 Complaints

Either NERC or Regional Entities may receive Complaints alleging violations of a Reliability Standard. The Compliance Enforcement Authority will conduct a review of each Complaint it receives to determine if the Complaint provides sufficient basis for initiating another compliance monitoring or enforcement process, except that NERC will review any Complaint where the Compliance Enforcement Authority determines it cannot conduct the review, or if the complainant wishes to remain anonymous or specifically requests NERC to conduct the review of the Complaint.

If the Complaint is submitted to NERC, NERC will forward the information to the Regional Entity, as appropriate.

All anonymous Complaints will be reviewed and any resulting compliance monitoring or enforcement processes conducted by NERC will be conducted in accordance with Section 3.7.2 to prevent disclosure of the identity of the complainant.

The Compliance Enforcement Authority conducting the review will determine if the Complaint may be closed as a result of the initial review and assessment or if it provides sufficient basis for initiating another compliance monitoring or enforcement process. The Compliance Enforcement Authority will report the results of its review of the Complaint to NERC. If, as a result of the initial review of the Complaint, the Compliance Enforcement Authority determines that initiating another compliance monitoring or enforcement process is warranted, the Compliance Enforcement Authority shall conduct that compliance monitoring or enforcement process in accordance with the applicable provisions of Section 3.0.

3.7.1 Complaint Process Steps

The detailed process steps for the Complaint process are as follows:

- The complainant notifies NERC or a Regional Entity using the NERC compliance hotline, submitting a NERC Complaint reporting form, or by other means. NERC and the Regional Entity shall post a link to the Complaint reporting form on their respective websites. The Complaint should include sufficient information to enable NERC or the Regional Entity to make an assessment regarding whether the initiation of another compliance monitoring or enforcement process is warranted. NERC or the Regional Entity may not act on a Complaint if the Complaint is incomplete and does not include sufficient information.

- If the Compliance Enforcement Authority determines that initiation of another compliance monitoring or enforcement process is warranted, it initiates the compliance monitoring or enforcement process in accordance with the applicable provisions of Section 3.0 or Section 5.0; otherwise it takes no further action. The Compliance Enforcement Authority notifies the complainant, the Registered Entity, and NERC of the initiation of the compliance monitoring or enforcement process. If the Compliance Enforcement Authority determines that initiation of another compliance monitoring or enforcement process is not warranted, it will notify the complainant, NERC, and the Registered Entity that no further action will be taken.

- The Compliance Enforcement Authority fully documents the Complaint and the Complaint review, and whether another compliance monitoring or enforcement process is warranted.

3.7.2 Anonymous Complainant Notification Procedure

A complainant who believes, or has information indicating, there has been a violation of a Reliability Standard, and wishes to remain anonymous, can report the information and request

that the complainant's identity not be disclosed.[2] All Complaints lodged by a person or entity requesting that the complainant's identity not be disclosed shall be investigated by NERC following the procedural steps described in Section 3.7.1. Anonymous Complaints received by a Regional Entity will either be directed to NERC or the Regional Entity will collect and forward the information to NERC, at the Regional Entity's discretion. Neither NERC nor the Regional Entity shall disclose the identity of any person or entity reporting information indicating violations of Reliability Standards to NERC or to a Regional Entity that requests that his/her/its identity not be revealed. The identity of the complainant will only be known by NERC and in the case where a Regional Entity collects the information, by NERC and the Regional Entity. If the Compliance Enforcement Authority determines that initiation of another compliance monitoring and enforcement process is not warranted, it will notify the complainant, NERC, and the Registered Entity that no further action will be taken.

3.8 Preliminary Screen

If the Compliance Enforcement Authority obtains information, through one of the compliance monitoring processes described in this Section 3.0 or by any other means, that indicates a potential noncompliance with a Reliability Standard Requirement, the Compliance Enforcement Authority shall conduct a Preliminary Screen of the potential noncompliance. The Preliminary Screen shall be conducted within five (5) business days after the Compliance Enforcement Authority identifies the potential noncompliance, except that (i) if the Compliance Enforcement Authority identifies the potential noncompliance during a Compliance Audit, the Preliminary Screen shall be conducted immediately following the exit briefing of the Registered Entity, and (ii) if the Compliance Enforcement Authority identifies the potential noncompliance during a Compliance Investigation, the Preliminary Screen shall be conducted immediately after the Registered Entity is first notified of the potential noncompliance identified by the Compliance Investigation.

A Preliminary Screen shall be limited to determining whether:

(1) the entity allegedly involved in the potential noncompliance is a Registered Entity;

(2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to the entity, has been approved by the Applicable Governmental Authority, and is in effect at the time of the potential noncompliance; and

(3) if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation that is currently being processed.

If the Preliminary Screen results in an affirmative determination with respect to the above criteria, a Possible Violation exists and the Compliance Enforcement Authority shall proceed in

[2]NERC has established a Compliance Hotline that may be used for the submission of Complaints by persons or entities that do not want his/her/its identity disclosed (see www.nerc.com for additional information).

accordance with Section 5.0, unless ~~an alternative enforcement~~the Compliance Exception ~~p~~Process is used in accordance with Section 3A.0.

The Compliance Enforcement authority shall maintain records of all Preliminary Screens.

3A.0 ENFORCEMENT DISCRETION

Not all instances of noncompliance with Reliability Standards require the same type of processing and documentation. Noncompliance that does not pose a serious or substantial risk to the reliability of the Bulk Power System may be resolved through streamlined processes, when appropriate, consistent with processes approved by NERC and Applicable Governmental Authorities.

Absolute adherence to the enforcement process set out in section 5.0 may not be the most appropriate, efficient, or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the Compliance Enforcement Authority, and the Registered Entity.

The Find, Fix, Track, and Report and the Compliance Exception processes are alternatives to the process outlined in section 5.0. ~~The Find, Fix, Track, and Report process may be used to address noncompliance posing a minimal or moderate risk to the reliability of the Bulk Power System.~~

3A.1 Compliance Exception Process

The Compliance Exception~~s~~ process may be used to address noncompliance posing a minimal risk to the reliability of the Bulk Power System, unless an Applicable Governmental Authority authorizes expansion of the program. Compliance Exceptions are not included in a Registered Entity's compliance history for penalty purposes. However, a Compliance Enforcement Authority must (a) consider a history of C~~c~~ompliance E~~e~~xceptions where the failure to fully remediate the underlying compliance matter contributes to a subsequent serious or substantial noncompliance and (b) assess subsequent noncompliance to determine whether a Registered Entity should continue to qualify for Compliance Exception treatment.

The Compliance Exception process requires that:

(1) The Registered Entity mitigates the noncompliance; and

(2) The facts and circumstances of the noncompliance, including those associated with the determination of the level of risk and the related mitigation, are available for review by NERC and Applicable Governmental Authorities; and

(3) The noncompliance is tracked and analyzed as necessary and appropriate to identify emerging risks and other pertinent trends; and

(4) The Registered Entity is provided the opportunity to object to the use of the ~~alternative approach~~Compliance Exception Process to resolution of the noncompliance.

Changes to the processes and principles articulated in this section must be approved by Applicable Governmental Authorities.

~~**3A.2 Find, Fix, Track and Report Process**~~

~~The Find, Fix, Track and Report process may be used to address noncompliance posing a minimal or moderate risk to the reliability of the Bulk Power System.~~

~~The Find, Fix, Track, and Report process and the Compliance Exception process requires that:~~

- ~~The Registered Entity mitigates the noncompliance; and~~
- ~~The facts and circumstances of the noncompliance, including those associated with the determination of the level of risk and the related mitigation, are available for review by NERC and Applicable Governmental Authorities; and~~
- ~~The noncompliance is tracked and analyzed as necessary and appropriate to identify emerging risks and other pertinent trends; and~~
- ~~The Registered Entity is provided the opportunity to object to the use of the alternative approach to resolution of the noncompliance.~~

~~Changes to the processes and principles articulated in this section must be approved by Applicable Governmental Authorities.~~

4.0 ANNUAL IMPLEMENTATION PLANS

4.1 NERC Compliance Monitoring and Enforcement Program Implementation Plan

NERC will maintain and update the NERC Implementation Plan, to be carried out by Compliance Enforcement Authorities in the performance of their responsibilities and duties in implementing the NERC Compliance Monitoring and Enforcement Program. The NERC Implementation Plan will be provided to the Regional Entities on or about September 1 of each year and will ~~specify~~ identify risk elements related to the Reliability Standards ~~requiring reporting by Registered Entities~~to be considered for compliance oversight ~~to~~ by the Compliance Enforcement Authority ~~to provide verification of compliance through one of the monitoring methods described in this Compliance Program~~. The NERC Implementation Plan will be posted on the NERC website. NERC may update and revise the NERC Implementation Plan during the course of the year as necessary. Regional Entities have discretion to make modifications to the NERC Implementation Plan with respect to individual Registered Entities.

4.2 Regional Implementation Plan

By on or about October 1 of each year, each Regional Entity will submit a Regional Implementation Plan for the following calendar year to NERC for review and approval. The Regional Implementation Plan and the Regional Entity's other relevant Compliance Program documents shall be posted on the Regional Entity's website. The Regional Entity may update

and revise the Regional Entity Implementation Plan during the course of the year as necessary, with NERC approval, or as required by NERC. Regional Entities have discretion to make modifications to the Regional Entity Implementation Plan with respect to individual Registered Entities.

5.0 ENFORCEMENT ACTIONS

The Compliance Enforcement Authority shall determine (i) whether there have been violations of Reliability Standards by Registered Entities within the Compliance Enforcement Authority's Area of Responsibility, and (ii) if so, the appropriate Mitigating Activities, and Penalties and sanctions, as prescribed in the NERC *Sanction Guidelines* (Appendix 4B to the NERC Rules of Procedure). NERC will work to achieve consistency in the application of the *Sanction Guidelines* by Regional Entities by direct oversight and review of Penalties and sanctions, and each Regional Entity shall provide to NERC such information as is requested by NERC concerning any Penalty, sanction, or Mitigating Activities imposed by the Regional Entity.

The imposition and acceptance of Penalties and sanctions shall not be considered an acceptable alternative to any Registered Entity's continuing obligation to comply with the Reliability Standards.

The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies be made of Documents, data and information and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel. If Documents, data or information requested from a Registered Entity in connection with an enforcement process are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

The following enforcement process is undertaken by the Compliance Enforcement Authority following identification of a Possible Violation of a Reliability Standard Requirement by a Registered Entity. However, under the circumstances presented by some Possible Violations, Alleged Violations or Confirmed Violations, absolute adherence to the following enforcement process, to the exclusion of other approaches, may not be the most appropriate, efficient or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the Compliance Enforcement Authority and the Registered Entity. In such circumstances, other approaches may be considered and employed. The Registered Entity shall be entitled to object to the use of any such other approach.

5.1 Notice of Possible Violation

If a Preliminary Screen conducted in accordance with Section 3.8 results in an affirmative determination with respect to the Preliminary Screen criteria, a Possible Violation exists. Unless the Compliance Exception process in Section 3A.0 is used to address the Possible Violation, ~~T~~the Compliance Enforcement Authority shall issue a Notice of Possible Violation to the Registered Entity. The Notice of Possible Violation shall:

(i) state that a Possible Violation by the Registered Entity has been identified;

(ii) provide a brief description of the Possible Violation, including the Reliability Standard requirement(s) and, if known, the date(s) involved; and

(iii) instruct the Registered Entity to retain and preserve all data and records relating to the Possible Violation.

Upon issuing a Notice of Possible Violation, the Compliance Enforcement Authority reports the Possible Violation to NERC. NERC reports the Possible Violation to the Board of Trustees Compliance Committee and submits a Notice of Possible Violation, on a confidential basis, to FERC and to other Applicable Governmental Authorities, as applicable. Any such notice to FERC or to other Applicable Governmental Authorities shall be provided in accordance with Section 8.0, Reporting and Disclosure.

5.2 Assessment of Possible Violation

After issuing a Notice of Possible Violation, the Compliance Enforcement Authority shall conduct an assessment of the facts and circumstances surrounding the Possible Violation to determine whether evidence exists to indicate the Registered Entity has violated the Reliability Standard Requirement(s) identified in the Notice of Possible Violation, or whether the Possible Violation should be dismissed. The Compliance Enforcement Authority may consider any additional information to demonstrate that the Possible Violation should be dismissed or modified or resolved through the Find, Fix, Track and Report (FFT) process in section 5.2A.

5.2A FFT Process

The Find, Fix, Track and Report process may be used to address noncompliance posing a minimal or moderate risk to the reliability of the Bulk Power System.

The FFT process requires that:

(1) The Registered Entity mitigates the noncompliance; and

(2) The facts and circumstances of the noncompliance, including those associated with the determination of the level of risk and the related mitigation, are available for review by NERC and Applicable Governmental Authorities; and

(3) FFTs are tracked and analyzed as necessary by NERC as appropriate to identify emerging risks and other pertinent trends; and

(4) The Registered Entity is provided the opportunity to object to the use of the FFT process to resolution of the noncompliance.

5.3 Notification to Registered Entity of Alleged Violation

If the Compliance Enforcement Authority determines, based on an assessment of the facts and circumstances surrounding a Possible Violation, that evidence exists to indicate a Registered Entity has violated a Reliability Standard, the Compliance Enforcement Authority shall notify the Registered Entity of the determination of the Alleged Violation, through issuance of a Notice of Alleged Violation and Proposed Penalty or Sanction or similar notification, and shall report the Alleged Violation to NERC The notification of Alleged Violation shall be transmitted by the Compliance Enforcement Authority to the Registered Entity by electronic mail and shall be effective as of the date of the electronic mail message from the Compliance Enforcement Authority transmitting the notification. The notification of Alleged Violation shall include, at a minimum:

(i) the Reliability Standard and Requirement(s) thereof the Registered Entity has allegedly violated,

(ii) the date and time the Alleged Violation occurred (or is occurring),

(iii) the facts the Compliance Enforcement Authority believes demonstrate or constitute the Alleged Violation,

(iv) the proposed Penalty or sanction, if any, determined by the Compliance Enforcement Authority to be applicable to the Alleged Violation in accordance with the NERC *Sanction Guidelines*, including an explanation of the basis on which the particular Penalty or sanction was determined to be applicable,

(v) notice that the Registered Entity shall, within thirty (30) days, elect one of the following options or the Compliance Enforcement Authority will deem the Registered Entity to have accepted the determination of violation and proposed Penalty or sanction:

1. agree with the Alleged Violation and proposed Penalty or sanction, and agree to submit and implement a Mitigation Plan or other Mitigating Activities to correct the violation and its underlying causes, and may provide a response in accordance with Section 5.4, or

2. agree with the Alleged Violation and agree to submit and implement a Mitigation Plan or other Mitigating Activities to eliminate the violation and its underlying causes, but contest the proposed Penalty or sanction, and may provide a response in accordance with Section 5.4, or

3. contest both the Alleged Violation and proposed Penalty or sanction,

(vi) notice that the Registered Entity may elect to submit a Mitigation Plan while contesting the Alleged Violation and/or the proposed Penalty or sanction, and that submission of a Mitigation Plan will not waive the Registered Entity's right to contest the Alleged Violation and/or the proposed Penalty or sanction;

(vii) notice that if the Registered Entity elects to contest the Alleged Violation and/or the proposed Penalty or sanction, the Registered Entity may elect to have a hearing conducted pursuant to either (i) the short-form procedure in Section 1.3.4, or (ii) the general hearing procedure, in **Attachment 2, Hearing Procedures**, and

(viii) required procedures to submit the Registered Entity's Mitigation Plan.

NERC shall notify FERC of the Alleged Violation and, if the Alleged Violation pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, shall notify such other Applicable Governmental Authority of the Alleged Violation, within two (2) business days of receipt from the Compliance Enforcement Authority. Any such notice to FERC or to another Applicable Governmental Authority shall be provided in accordance with Section 8.0, Reporting and Disclosure.

5.4 Registered Entity Response

If the Registered Entity agrees with, does not contest, or does not respond to the notification of Alleged Violation within thirty (30) days following the date of the notification of Alleged Violation by electronic mail, it shall be deemed to have accepted the Compliance Enforcement Authority's determination of violation and Penalty or sanction, and the Compliance Enforcement Authority shall issue a Notice of Confirmed Violation or similar notification to the Registered Entity and shall report the Confirmed Violation to NERC. At the time of notifying the Registered Entity of the Confirmed Violation, the Compliance Enforcement Authority shall also provide notice to the Registered Entity that it may provide a written explanatory statement to accompany the filing with FERC and public posting of the Confirmed Violation. The Registered Entity's statement must include the name, title, and signature of an officer, employee, attorney or other authorized representative of the Registered Entity.

If the Registered Entity contests the Alleged Violation or the proposed Penalty or sanction, the Registered Entity shall submit to the Compliance Enforcement Authority, within thirty (30) days following the date of the notification of the Alleged Violation, a response explaining its position, signed by an officer, employee, attorney or other authorized representative together with any supporting information and documents. The Compliance Enforcement Authority shall schedule a conference with the Registered Entity within ten (10) business days after receipt of the response. If the Compliance Enforcement Authority and the Registered Entity are unable to resolve all issues within forty (40) days after the Registered Entity's response, the Registered Entity may request a hearing. The Compliance Enforcement Authority and the Registered Entity may agree in writing to extend the forty (40) day period. If no hearing request is made prior to the end of the forty (40) day period, the violation will be become a Confirmed Violation.

If a hearing is requested the Compliance Enforcement Authority shall initiate the hearing process in accordance with **Attachment 2, Hearing** Procedures.

5.5 Hearing Process for Compliance Hearings

The Compliance Enforcement Authority hearing process is set forth in **Attachment 2**.

5.6 Settlement Process

The Registered Entity can request settlement negotiations at any time, including prior to the issuance of notification of an Alleged Violation; however, the Compliance Enforcement Authority may decline to engage in or to continue settlement negotiations after a Possible Violation or Alleged Violation becomes a Confirmed Violation in accordance with Section 5.4. The Registered Entity or the Compliance Enforcement Authority may terminate settlement negotiations at any time. Where the Compliance Enforcement Authority has agreed top engage in settlement negotiations, the running of the time period specified in Section 5.4 for the Registered Entity to respond to the notification of Alleged Violation is suspended until settlement negotiations are concluded or terminate. NERC shall be notified of all settlement negotiations and may participate in any settlement negotiations. All settlement negotiations will be confidential until such time as the settlement is approved by NERC. For all settlement discussions, the Compliance Enforcement Authority shall require the Registered Entity to designate an individual(s) authorized to negotiate on its behalf.

The Compliance Enforcement Authority may consider all relevant facts in settlement negotiations. A settlement agreement must ensure that the reliability of the Bulk Power System will not be compromised by the settlement and that a violation of a Reliability Standard will not occur as a result of the settlement. All settlement agreements must provide, if the settlement is approved, for waiver of the Registered Entity's right to further hearings and appeal.

The Compliance Enforcement Authority and the Registered Entity will execute a settlement agreement setting forth the final settlement terms including all Penalties, sanctions and mitigation requirements provided for in the final settlement.

The Compliance Enforcement Authority shall report the terms of all settlements of compliance matters to NERC. NERC will review the settlement for the purpose of evaluating its consistency with other settlements entered into for similar violations or under other, similar circumstances. The Registered Entity may submit an explanatory statement, conforming to the requirements of Section 5.4, to be included in the settlement agreement and which shall be subject to consent of the Compliance Enforcement Authority as part of the settlement agreement. The settlement agreement may state that the Registered Entity (i) admits the Alleged Violation, or (ii) does not contest the Alleged Violation, or (iii) neither admits nor denies the Alleged Violation, but may not state that the Registered Entity denies the Alleged Violation. Based on this review, NERC will either approve the settlement or reject the settlement and notify the Compliance Enforcement Authority of any changes to the settlement that would result in approval, and within five (5) business days the Compliance Enforcement Authority will in turn notify the Registered Entity. If NERC rejects the settlement, the Compliance Enforcement Authority will attempt to negotiate a revised settlement agreement with the Registered Entity including any changes to the settlement specified by NERC.

NERC will report the approved settlement of the violation to FERC and, if the settlement relates to a Registered Entity or to a portion of the Bulk Power System over which another Applicable

Governmental Authority has jurisdiction, to such other Applicable Governmental Authority. Any such report shall be provided in accordance with Section 8.0, Reporting and Disclosure. NERC will also publicly post the violation settled (regardless of whether the settlement includes or does not include an admission of a violation) and the resulting Penalty or sanction provided for in the settlement. This posting shall include a copy of the settlement or a description of the terms of the settlement, and a copy of any Mitigation Plan that is agreed to as part of the settlement, with any Critical Energy Infrastructure Information and Confidential Information redacted. The Compliance Enforcement Authority will issue a letter setting forth the final settlement terms including all Penalties, sanctions and mitigation requirements provided for in the final settlement. Postings of Notices of Confirmed Violations are addressed in Section 8.0.

5.7 NERC Appeal Process

A Registered Entity or the Compliance Enforcement Authority may appeal the decision of a Regional Entity Hearing Body to NERC, as provided for in NERC Rules of Procedure, Section 409.

On appeal, NERC shall either affirm the decision or remand to the Compliance Enforcement Authority with reasons for its remand, which may include a direction to the Compliance Enforcement Authority to revise the decision. If NERC affirms the decision, the Compliance Enforcement Authority shall issue a Notice of Confirmed Violation to the Registered Entity. If NERC directs the Compliance Enforcement Authority to revise the decision, a Registered Entity that was the subject of the decision or the Compliance Enforcement Authority may reopen the proceeding on any issue whose resolution is affected by NERC's directive, irrespective of whether the issue was previously litigated, settled or unopposed.

5.8 Notification of Confirmed Violation

A Notice or other notification of Confirmed Violation issued to a Registered Entity pursuant to Sections 5.4 or 5.7 shall include a detailed record of the enforcement action, including the facts and circumstances analyzed and the information on which the Compliance Enforcement Authority relied in proposing a Penalty or sanction.

After NERC receives a notification of Confirmed Violation from the Compliance Enforcement Authority, NERC shall review the notification of Confirmed Violation and utilize the information therein to prepare a Notice of Penalty. NERC shall advise the Compliance Enforcement Authority of any additional detail or further development of the factual findings that NERC deems necessary before the Notice of Penalty can be issued.

NERC may direct the Compliance Enforcement Authority to revise a Penalty determination, in which case the Registered Entity subject to the Penalty, or the Compliance Enforcement Authority, as applicable, may reopen the proceedings on any issue on which the Penalty was based, irrespective of whether the issue was previously litigated, settled or unopposed.

5.9 Notice of Penalty

If (i) the Registered Entity accepts the Notice of Alleged Violation and Proposed Penalty or Sanction or other notification of enforcement action from the Compliance Enforcement

Authority, or (ii) a decision has been entered affirming an Alleged Violation and all appeals have been concluded, or (iii) a settlement agreement has been reached addressing the Possible Violation or Alleged Violation, NERC shall submit a Notice of Penalty to the Applicable Governmental Authority and provide a copy to the Compliance Enforcement Authority. The Compliance Enforcement Authority shall inform the Registered Entity that a Notice of Penalty is pending public filing, at least five (5) business days prior to the public filing and posting. NERC will file the Notice of Penalty with FERC and any other Applicable Governmental Authority no sooner than five (5) business days after NERC approves the Notice of Confirmed Violation or settlement agreement.

NERC shall file the Notice of Penalty with FERC and, if the Possible Violation or Alleged Violation pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority. Any such filing with FERC or with another Applicable Governmental Authority shall be made in accordance with Section 8.0, Reporting and Disclosure. NERC will include with the Notice of Penalty any statement provided by the Registered Entity as set forth in Sections 5.4 or 5.6.

The Penalty or sanction will be effective upon expiration of the thirty (30) day period following filing with FERC of the Notice of Penalty (or such longer period as ordered by FERC) or, if FERC decides to review the Penalty or sanction, upon final determination by FERC.

5.10 Completion of Enforcement Action

Following FERC approval of, or expiration of the period for action by FERC on, a Notice of Penalty filed by NERC, the Compliance Enforcement Authority shall issue a payment due notice and invoice to the Registered Entity. The payment due notice and invoice shall state the payment due date which shall be thirty (30) days from the date of the payment due notice and invoice. Upon payment of all monetary Penalties by the Registered Entity, the Compliance Enforcement Authority shall issue a notice confirming payment to the Registered Entity, and provide a copy of the notice confirming payment to NERC. Following the completion by the Registered Entity of all requirements set forth in the Notice of Penalty and any settlement agreement, the Compliance Enforcement Authority shall issue the Registered Entity a Notice of Completion of Enforcement Action.

If the Compliance Enforcement Authority dismisses or disposes of a Possible Violation or Alleged Violation that does not become a Confirmed Violation, the Compliance Enforcement Authority shall issue a Notice of Completion of Enforcement Action to the Registered Entity.

A copy of the Notice of Completion of Enforcement Action shall also be provided to NERC by the Compliance Enforcement Authority.

The Notice of Completion of Enforcement Action shall include a release of any data retention directives that were previously issued to the Registered Entity in connection with the matter. Upon issuance of a Notice of Completion of Enforcement Action, tracking of the violation is completed, and the enforcement action shall be closed.

5.11 Special Procedures for an Enforcement Action Against an ISO/RTO Where the Monetary Penalty May be Allocated by the ISO/RTO to Other Entities

A Registered Entity that is an ISO/RTO may have authority to allocate, pursuant to a proceeding under section 205 of the Federal Power Act, some or all of a monetary Penalty imposed on the ISO/RTO for violation of a Reliability Standard, to another entity(ies) that the Compliance Enforcement Authority, NERC or FERC determines was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation of the Reliability Standard. This section sets forth the procedures to be followed when an ISO/RTO that has received a Notice of Possible Violation requests a determination by the Compliance Enforcement Authority that another entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation.

The procedures in this section apply only where an ISO/RTO requests a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation (if confirmed) identified in a Notice of Possible Violation issued to the ISO/RTO, and shall not apply where the ISO/RTO anticipates or is entitled to allocate or assign a monetary Penalty among all, or an identified segment of, its members, customers or users, pursuant to general cost recovery provisions in the ISO/RTO's tariffs, agreements or governance documents and regardless of actual fault or responsibility of the entities to whom the monetary Penalty is issued for the violation.

5.11.1 ISO/RTO's Request for Determination and Notice to Other Entity(ies)

In order to request the Compliance Enforcement Authority to make a determination in an enforcement action that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to a violation (if confirmed) of a Reliability Standard for which the ISO/RTO has received a Notice of Possible Violation, the ISO/RTO shall, no later than ten (10) business days after receiving the Notice of Possible Violation or such additional period as the Compliance Enforcement Authority may permit for good cause shown (i) submit a written request to the Compliance Enforcement Authority and (ii) issue a notice to the specified other entity(ies), each conforming to the requirements of the following two paragraphs of this section.

The ISO/RTO's written request to the Compliance Enforcement Authority shall contain:

(1) the Compliance Enforcement Authority's identification number for the Notice of Possible Violation;

(2) a statement that the ISO/RTO is requesting that the Compliance Enforcement Authority make a determination that a specified other entity(ies) was responsible, in whole or in part, for actions and omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation;

(3) the name(s) of, and contact information for, the specified other entity(ies), including name(s) and address(es) of the entity(ies) and name(s), telephone number(s) and e-mail address(es) of the contact person(s) for the other entity(ies);

(4) a statement that the ISO/RTO has authority to allocate some or all of the monetary Penalty to the specified other entity(ies), including citations to any supporting tariffs, agreements, orders, or governance documents, and a brief explanation to show that the specified other entity(ies) are subject to the tariffs, agreements, orders and/or other governance documents; and

(5) a brief statement of the factual basis on which the ISO/RTO contends in good faith that the specified other entity(ies) was responsible for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation. As the enforcement action proceeds, the ISO/RTO may supplement, expand or modify this explanation as additional information becomes available during the course of the enforcement action.

The ISO/RTO's notice to the specified other entity(ies) shall contain the following information:

(1) The name of the specified other entity, and the name, telephone number and e-mail address of the specified other entity's contact person (person to whom the notice is being sent);

(2) A statement that the ISO/RTO has received a Notice of Possible Violation from the Compliance Enforcement Authority, the Compliance Enforcement Authority's identification number for the Notice of Possible Violation, and contact information for the Compliance Enforcement Authority;

(3) A statement that the ISO/RTO has requested the Compliance Enforcement Authority to determine that the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, and that the ISO/RTO intends to seek to allocate to the specified other entity all or a portion of any monetary Penalty that is imposed on the ISO/RTO for the violation (if confirmed), if the Compliance Enforcement Authority determines the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation.

(4) A statement that the specified other entity should promptly contact the Compliance Enforcement Authority for further information and to request to participate in the enforcement action relating to the Notice of Possible Violation.

The ISO/RTO shall cause its notice to the specified other entity(ies) to be delivered to the other entity(ies) by next-business-day delivery using a delivery service that provides verification of delivery. The ISO/RTO shall provide the Compliance Enforcement Authority with (i) a copy of the notice sent to each specified other entity, and (ii) a copy of the delivery service's verification of delivery of the notice to each specified other entity.

5.11.2 Responses of the Compliance Enforcement Authority and the Specified Other Entity(ies) to ISO/RTO's Request for Determination and Notice

If (i) the ISO/RTO's written request meets the requirements of Section 5.11.1, the Compliance Enforcement Authority shall provide the specified other entity(ies) with a copy of a non-disclosure agreement (which shall include the specified other entity's agreement to comply with the confidentiality requirements of the Compliance Program and of Section 1500 of the NERC Rules of Procedure) that must be executed to obtain a copy of the Notice of Possible Violation and a copy of the ISO/RTO's written request to the Compliance Enforcement Authority for a determination that the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation. In addition, the Compliance Enforcement Authority shall advise the specified other entity(ies) that: (i) the specified other entity(ies) may elect not to participate in the enforcement action, and may submit a written statement to the Compliance Enforcement Authority stating why the specified other entity is not participating and providing any facts or information the other entity wishes to provide concerning the occurrence(s) that are the subject of the Notice of Possible Violation, and (ii) whether or not the specified other entity elects to participate in the enforcement action, the Compliance Enforcement Authority may determine that the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation.

If the ISO/RTO's written request meets the requirements of Section 5.11.1, then the specified other entity(ies) shall be permitted to participate in the enforcement action concerning the Notice of Possible Violation if the other entity(ies) submits a written request to participate to the Compliance Enforcement Authority and executes a non-disclosure agreement in the form provided by the Compliance Enforcement Authority. The specified other entity must submit its written request to participate prior to, as applicable (i) the date of execution of a settlement agreement between the Compliance Enforcement Authority and the ISO/RTO, or (ii) the date that the Compliance Enforcement Authority issues a Notice of Confirmed Violation to the ISO/RTO. The Compliance Enforcement Authority is not required to suspend or delay the enforcement process pending receipt of a request to participate from the specified other entity(ies), nor to revisit or redo any aspect of the enforcement process that has already occurred prior to receipt of the specified other entity(ies)'s written request to participate; however, upon receipt of a written request to participate and executed nondisclosure agreement from the specified other entity(ies), the Compliance Enforcement Authority shall suspend activity in the enforcement action until it has acted on the request to participate.

Upon receiving the specified other entity's written request to participate in the enforcement action and the other entity's executed nondisclosure agreement, the Compliance Enforcement Authority shall issue a notice to the ISO/RTO and to the specified other entity stating that the specified other entity is allowed to participate in the enforcement action. The Compliance Enforcement Authority's notice that the specified other entity is allowed to participate in the enforcement action shall include a copy of the Notice of Possible Violation originally issued to the ISO/RTO and, if a Notice of Alleged Violation and Proposed Penalty or Sanction or similar notification has been issued to the ISO/RTO, a copy of the latter Notice or notification. Upon receiving notice from the Compliance Enforcement Authority that it is allowed to participate in the enforcement action, the specified other entity may participate in the same manner as the ISO/RTO and shall be subject to all applicable requirements and deadlines specified in the NERC Compliance Program.

If the ISO/RO fails to meet the requirements of Section 5.11.1, the Compliance Enforcement Authority shall issue a notice to the ISO/RTO and to the specified other entity(ies) stating that the Compliance Enforcement Authority will not make the determination requested by the ISO/RTO and therefore the specified other entity will not be allowed to participate in the enforcement action relating to the Notice of Possible Violation.

5.11.3 Compliance Enforcement Authority's Notices to NERC

(a) Within five (5) business days after receiving an ISO/RTO's written request for a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to a violation identified in the Notice of Possible Violation issued to the ISO/RTO, the Compliance Enforcement Authority shall provide to NERC (i) a copy of the ISO/RTO's written request for a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, and (ii) the ISO/RTO's notice to the specified other entity(ies).

(b) On the same day that the Compliance Enforcement Authority issues a notice pursuant to Section 5.11.2 stating, as applicable, that (i) it will or will not make the determination requested by the ISO/RTO or (ii) the specified other entity(ies) are or are not allowed to participate in the enforcement action, the Compliance Enforcement Authority shall provide a copy of the notice to NERC and shall send a copy of the notice to any other entities that have been allowed to participate in the enforcement action.

5.11.4 Compliance Enforcement Authority's Determination

After issuing a notice pursuant to Section 5.11.3 that it will make a determination as to whether the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation that is the subject of the Notice of Possible Violation issued to the ISO/RTO, then, if the enforcement action is not resolved by a settlement agreement stating whether or not the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, the Compliance Enforcement Authority shall make, and include in its proposed Notice of Penalty, its determination of whether or not the specified other entity(ies) were responsible, in whole or in part, for actions or omissions that caused or contributed to the violation. The Compliance Enforcement Authority's determination shall only address whether or not the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation, and shall not address whether all or a part of any monetary Penalty imposed on the ISO/RTO for the violation should be allocated or assigned to the specified other entity(ies).

The specified other entity(ies) shall be entitled to request a hearing on the Compliance Enforcement Authority's determination pursuant to Section 1.3.1 of Attachment 2 of this Appendix 4C, and to appeal the Hearing Body's decision pursuant to Section 1.7.10 of Attachment 2 to this Appendix 4C, as though the specified other entity(ies) were a Registered Entity(ies).

5.11.5 Procedure Where ISO/RTO Members Are Allowed to Directly Assign Monetary Penalties for Violations of Reliability Standards to the ISO/RTO

If an ISO/RTO's tariffs, agreement or other relevant governance documents establish procedures that allow members of the ISO/RTO to directly assign to the ISO/RTO monetary Penalties imposed on the ISO/RTO member(s) for violations of Reliability Standards, then the ISO/RTO members may follow the same requirements of Sections 5.11.1 and 511.2 as are applicable to an ISO/RTO under those sections, and the ISO/RTO shall be afforded the same rights to participate in the enforcement action as a specified other entity under Sections 5.11.1, 5.11.2, and 5.11.4, subject to the same requirements and conditions specified in those sections. In such circumstances, the ISO/RTO shall be deemed to be a "specified other entity" for purposes of this Section.

5.11.6 Obligation to Pay Monetary Penalty

(a) The ISO/RTO shall be obligated and responsible to pay any monetary Penalty imposed by the Compliance Enforcement Authority on the ISO/RTO for violation of a Reliability Standard, in accordance with Section 5.10, (i) regardless of whether the Compliance Enforcement Authority has made a determination that a specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation, (ii) without regard to the timing of any separate proceeding(s) in which the ISO/RTO seeks to allocate some or all of the monetary Penalty to a specified other entity(ies), and (iii) without regard to whether or when the ISO/RTO receives payment from the specified other entity(ies).

(b) In an enforcement action subject to Section 5.11.5, the ISO/RTO member(s) shall be obligated and responsible to pay any monetary Penalty imposed by the Compliance Enforcement Authority on the ISO/RTO member(s) for violation of a Reliability Standard, regardless of whether or when the ISO/RTO members receive payment or reimbursement from the ISO/RTO.

6.0 MITIGATION OF VIOLATIONS OF RELIABILITY STANDARDS

The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies be made of Documents, data and information and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel. If

Documents, data, information or other reports requested from a Registered Entity in connection with development of a Mitigation Plan or other Mitigating Activities are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

6.1 Requirement for Submission of Mitigation Plans

A Registered Entity found to be in violation of a Reliability Standard shall file with the Compliance Enforcement Authority (i) a proposed Mitigation Plan to correct the violation, or (ii) a description of how the violation has been mitigated, and any requests for extensions of Mitigation Plans or a report of completed mitigation. A Registered Entity may also submit a proposed Mitigation Plan at any other time, including with a Self-Report, or, without admitting it has committed a violation, in response to a Notice of Possible Violation or notification of Alleged Violation.

6.2 Contents of Mitigation Plans

A Mitigation Plan shall include the following information:

- The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section 2.0.

- The Possible, Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.

- The cause of the Possible, Alleged or Confirmed Violation(s).

- The Registered Entity's action plan to correct the Possible, Alleged or Confirmed Violation(s).

- The Registered Entity's action plan to correct the cause of the Possible, Alleged or Confirmed Violation.

- The Registered Entity's action plan to prevent recurrence of the Possible, Alleged or Confirmed Violation(s).

- The anticipated impact of the Mitigation Plan on the Bulk Power System reliability and an action plan to mitigate any increased risk to the reliability of the Bulk Power System while the Mitigation Plan is being implemented.

- A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Possible, Alleged or Confirmed Violation(s) corrected.

- Implementation milestones no more than three (3) months apart for Mitigation Plans with

expected completion dates more than three (3) months from the date of submission. Additional violations could be determined for not completing work associated with accepted milestones.

- Any other information deemed necessary or appropriate.

The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity.

6.3 Timetable for Completion of Mitigation Plans

The Mitigation Plan shall be completed in accordance with its terms. At the Compliance Enforcement Authority's discretion, the completion deadline may be extended for good cause including, but not limited to: (i) operational issues such as the inability to schedule an outage to complete Mitigating Activities, and (ii) construction requirements in the Mitigation Plan that require longer to complete than originally anticipated. If the Mitigation Plan extends beyond the next applicable reporting/assessment period, sanctions for any violation of the applicable Reliability Standard(s) occurring during the implementation period will be held in abeyance and will be waived if the Mitigation Plan is satisfactorily completed.

Any violations assessed during the period of time the accepted Mitigation Plan is being implemented will be recorded by the Compliance Enforcement Authority with associated sanctions or Penalties. Regional Entities will report any findings of violations recorded during this time period to NERC with the notation that the Registered Entity is working under an accepted Mitigation Plan with an extended completion date with Penalties and sanctions held in abeyance until completion of the Mitigation Plan. Upon completion of the accepted Mitigation Plan in accordance with Section 6.6, the Compliance Enforcement Authority will notify the Registered Entity that any findings of violations of the applicable Reliability Standard during the period that the accepted Mitigation Plan was being implemented have been waived and no Penalties or sanctions will apply. Regional Entities will also notify NERC of any such waivers of violations of Reliability Standards.

A request for an extension of any milestone or the completion date of the accepted Mitigation Plan by a Registered Entity must be received by the Compliance Enforcement Authority at least five (5) business days before the original milestone or completion date. The Compliance Enforcement Authority may accept a request for an extension or modification of a Mitigation Plan if the Compliance Enforcement Authority determines the request is justified, and shall notify NERC of the extension or modification within five (5) business days.

If a Mitigation Plan submitted by a Registered Entity is rejected by the Regional Entity acting as Compliance Enforcement Authority or the Hearing Body in accordance with Section 6.5, the Registered Entity shall be subject to any findings of violation of the applicable Reliability Standards during the period the Mitigation Plan was under consideration and to imposition of any Penalties or sanctions imposed for such violations.

6.4 Submission of Mitigation Plans

A Mitigation Plan may be submitted at any time but shall have been submitted by the Registered Entity within thirty (30) days after being served the notification of Alleged Violation, if the Registered Entity does not contest the Alleged Violation and Penalty or sanction, or shall be reflected in a settlement agreement or Notice of Penalty. If the Registered Entity disputes the Alleged Violation or the Penalty or sanction, the Registered Entity shall submit its Mitigation Plan within ten (10) business days following issuance of the written decision of the Hearing Body, unless the Registered Entity elects to appeal the Hearing Body's determination to NERC. The Registered Entity may choose to submit a Mitigation Plan while it contests an Alleged Violation or Penalty or sanction or in response to a Notice of Possible Violation; such submission shall not be deemed an admission of a violation or the appropriateness of a Penalty or sanction. If the Registered Entity has not yet submitted a Mitigation Plan, or the Registered Entity submits a Mitigation Plan but it is rejected by the Regional Entity acting as Compliance Enforcement Authority or the Hearing Body in accordance with Section 6.5, any subsequent violations of the Reliability Standard identified by the Compliance Enforcement Authority before the Hearing Body renders its decision will not be held in abeyance and will be considered as repeat violations of the Reliability Standard.

6.5 Review and Acceptance or Rejection of Proposed Mitigation Plans

Unless the time period is extended by the Compliance Enforcement Authority, it will complete its review of the Mitigation Plan, and will issue a written statement accepting or rejecting the Mitigation Plan, within thirty (30) days of receipt; otherwise the Mitigation Plan will be deemed accepted. In order to extend the initial or an extended period for review of the Mitigation Plan, the Compliance Enforcement Authority shall, within the initial or extended review period, notify the Registered Entity (and NERC if NERC is not the Compliance Enforcement Authority) that the review period is being extended and identify the date by which the Compliance Enforcement Authority will complete its review of the Mitigation Plan. The Compliance Enforcement Authority's extension notice shall also state that if the Compliance Enforcement Authority has not issued a notice by the end of the extended review period either stating that the Compliance Enforcement Authority accepts or rejects the proposed Mitigation Plan or further extending the Compliance Enforcement Authority's period for review of the Mitigation Plan, the Mitigation Plan will be deemed accepted.

If the Compliance Enforcement Authority rejects a Mitigation Plan, the Compliance Enforcement Authority will provide the Registered Entity with a written statement describing the reasons for the rejection, and will require the Registered Entity to submit a revised Mitigation Plan by the Required Date. The Compliance Enforcement Authority will notify the Registered Entity within ten (10) business days after receipt of a revised Mitigation Plan whether the Compliance Enforcement Authority will accept or reject the revised Mitigation Plan and provide a written statement describing the reasons for rejection and the Required Date for the second revised Mitigation Plan. If the second review results in rejection of the Mitigation Plan, the Registered Entity may request a hearing in accordance with the Hearing Procedures, by submitting to the Compliance Enforcement Authority a written request for hearing including an explanation of why the Mitigation Plan should be accepted. After the hearing is completed, the Compliance Enforcement Authority will issue a written statement accepting a Mitigation Plan it deems as appropriate.

Within five (5) business days after a Regional Entity accepts a Mitigation Plan, the Regional Entity (i) will notify NERC and the Registered Entity of the acceptance of the Mitigation Plan and (ii) will provide the accepted Mitigation Plan to NERC. NERC will review the accepted Mitigation Plan and, within thirty (30) days following its receipt of the Mitigation Plan from the Regional Entity, will notify the Regional Entity and the Registered Entity, on a contemporaneous basis, as to whether the Mitigation Plan is approved or disapproved by NERC. If NERC disapproves a Mitigation Plan that was accepted by the Regional Entity, NERC shall state its reasons for the rejection, and may state the changes to the Mitigation Plan that would result in approval by NERC. The Registered Entity shall not be subject to findings of violations of the specific Requirements of Reliability Standards that are the subject of the Mitigation Plan or to imposition of Penalties or sanctions for such violations with respect to the period of time the Mitigation Plan was under consideration by NERC and for a reasonable period following NERC's disapproval of the Mitigation Plan, so long as the Registered Entity promptly submits a modified Mitigation Plan that addresses the concerns identified by NERC.

If a Registered Entity submits a Mitigation Plan prior to issuance of a notification of Confirmed Violation or entry into a settlement, such as with a Self-Report or in response to a Notice of Possible Violation, the Regional Entity may provisionally accept the proposed Mitigation Plan. If the Regional Entity subsequently determines, upon completing its assessment of the Possible Violation, that the facts and circumstances are different than those on which the accepted Mitigation Plan was based, the Regional Entity may, by notice to the Registered Entity and to NERC, require the Registered Entity to submit a revised Mitigation Plan that fully addresses the facts and circumstances of the violation. The Regional Entity's notice shall state the additional or different facts and circumstances that need to be addressed in the revised Mitigation Plan. The Registered Entity shall submit a revised Mitigation Plan in response to the notice within thirty (30) days following the date of the notice, unless the Regional Entity specifies or allows a longer time period. The Registered Entity's revised Mitigation Plan shall be subject to review and acceptance or rejection by the Regional Entity and by NERC in accordance with this Section 6.5. If the Regional Entity issues a notification of Confirmed Violation or enters into a settlement with the Registered Entity and does not identify a need to request modifications to the provisionally-accepted Mitigation Plan based on additional or different facts and circumstances, the Regional Entity shall issue a notice to the Registered Entity, with a copy to NERC, stating that the "provisional" nature of the acceptance is terminated and the acceptance is final. The Regional Entity shall issue such notice within five (5) business days of issuance of the Notice of Confirmed Violation or entry into the settlement.

NERC will submit to FERC, as non-public information, an approved Mitigation Plan relating to violations of Reliability Standards within seven (7) business days after NERC approves the Mitigation Plan. NERC shall publicly post the approved Mitigation Plan as part of the public posting of the related Notice of Penalty in accordance with Section 8.0 or settlement in accordance with Section 5.6.

6.6 Completion/Confirmation of Implementation of Mitigation Plans

The Registered Entity shall provide updates at least quarterly to the Compliance Enforcement Authority on the progress of the Mitigation Plan. The Compliance Enforcement Authority will track the Mitigation Plan to completion and may conduct on-site visits and review status during Compliance Audit to monitor Mitigation Plan implementation.

Upon completion of the Mitigation Plan, the Registered Entity shall provide to the Compliance Enforcement Authority certification, signed by an officer, employee, attorney or other authorized representative of the Registered Entity, that all required actions described in the Mitigation Plan have been completed and shall include data or information sufficient for the Compliance Enforcement Authority to verify completion. The Compliance Enforcement Authority shall request such data or information and conduct follow-up assessments, on-site or other Spot Checks, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed.

In the event all required actions in the Mitigation Plan are not completed within the applicable deadline including any extensions of the original deadline granted under Section 6.3, any violation(s) of a Reliability Standard subject to the Mitigation Plan that occurred during the originally scheduled time period for completion will be enforced immediately and a new Mitigation Plan must be submitted for acceptance by the Compliance Enforcement Authority. In addition, the Compliance Enforcement Authority may conduct a Compliance Audit of, or issue a Remedial Action Directive to, the Registered Entity.

Upon request by NERC, the Regional Entity will provide to NERC the quarterly status reports and such other information as NERC requests. The Regional Entity will notify NERC when each Mitigation Plan is verified to have been completed.

6.7 Recordkeeping

The Compliance Enforcement Authority will maintain a record containing the following information for each Mitigation Plan:

- Name of Registered Entity.
- The date of the violation.
- Monitoring method by which the violation was detected, i.e., Self-Certification, Self-Report, Compliance Audit, Compliance Investigation, Complaint, etc.
- Date(s) of Notice of Possible Violation and notification of Alleged Violation (if applicable).
- Expected and actual completion date of the Mitigation Plan and major milestones.
- Expected and actual completion date for each required action.
- Accepted changes to milestones, completion dates, or scope of Mitigation Plan.
- Registered Entity's completion notice and data submitted as evidence of completion.

7.0 REMEDIAL ACTION DIRECTIVES

The Compliance Enforcement Authority may issue a Remedial Action Directive when such action is immediately necessary to protect the reliability of the Bulk Power System from an

imminent or actual threat. A Remedial Action Directive may include, but is not limited to, any of the following: specifying operating or planning criteria, limits, or limitations; requiring specific system studies; defining operating practices or guidelines; requiring confirmation of data, practices, or procedures through inspection testing or other methods; requiring specific training for personnel; requiring development of specific operating plans; directing a Registered Entity to develop and comply with a plan to remediate a violation; imposing increased auditing or additional training requirements; and requiring a Registered Entity to cease an activity that may constitute a violation of a Reliability Standard.

A Remedial Action Directive may be issued to a Registered Entity at any time, including during any procedures relating to a Possible Violation or an Alleged Violation of a Reliability Standard. The Compliance Enforcement Authority will specify whether a Remedial Action Directive obviates the need for a Mitigation Plan.

Prior to issuing a Remedial Action Directive, the Compliance Enforcement Authority shall consult the Reliability Coordinator for the Registered Entity.

Any Remedial Action Directive must be provided in a notice to the Registered Entity and shall include: (i) a list of the Possible Violation(s) or Alleged Violation(s) of Reliability Standards that are the basis for issuance of the Remedial Action Directive; (ii) a discussion of the factual basis for the Remedial Action Directive; (iii) the requirements the Compliance Enforcement Authority is imposing to remove the imminent or actual threat to the reliability of the Bulk Power System; (iv) a deadline for compliance and a schedule for specific periodic updates to the Compliance Enforcement Authority; and (v) notice to the Registered Entity that failure to comply with the directive by the Required Date may result in further Remedial Action Directives or significantly increased sanctions.

The Compliance Enforcement Authority will cause the notice of the Remedial Action Directive to be delivered to the Registered Entity by (i) electronic mail to the Registered Entity's CEO or equivalent and copied to the Registered Entity's designated contact person for reliability matters and (ii) by a recognized express courier service that provides tracking and verification of delivery to the recipient. The notice will be deemed received on the earlier of the actual date of receipt of the electronic submission or receipt of the express courier delivery as specified by the express courier service's verification of delivery. The Compliance Enforcement Authority will monitor implementation of Remedial Action Directives as necessary to verify compliance.

The Compliance Enforcement Authority will notify NERC within two (2) business days after issuing a Remedial Action Directive and will copy NERC on all correspondence sent to the Registered Entity.

Once the Compliance Enforcement Authority has given the Registered Entity notice of the Remedial Action Directive, the Registered Entity may contest the Remedial Action Directive by giving written notice to the Compliance Enforcement Authority within two (2) business days following the date of actual receipt of notice of the Remedial Action Directive. Due to the urgency of resolving any objections to a Remedial Action Directive, the hearing shall be conducted under the expedited hearing process set forth in Section 1.9 of **Attachment 2, Hearing Procedures**. Notice to contest the Remedial Action Directive and participation in the hearing process set forth in Section 1.9 of **Attachment 2, Hearing Procedures** shall constitute

the Registered Entity's right to appeal the Remedial Action Directive. The Registered Entity may elect not to implement the Remedial Action Directive until the hearing process is completed, or may proceed with implementing the Remedial Action Directive even if it is contesting the Remedial Action Directive.

8.0 REPORTING AND DISCLOSURE

8.1 Information to be Reported

Regional Entities shall promptly submit to NERC electronic reports containing current information concerning the information listed below. NERC will work with Regional Entities to specify form, content, timing, and method of submitting reports and notices.

(1) The status of the review and assessment of all Possible Violations, Alleged Violations and Confirmed Violations of Reliability Standards by Registered Entities,

(2) The potential impact of any Alleged Violation or Confirmed Violation on the reliability of the Bulk Power System,

(3) Sanctions and Penalties,

(4) Remedial Action Directives imposed,

(5) Mitigation Plans, and

(6) The name of a Regional Entity staff person knowledgeable about the information to serve as a point of contact.

8.2 Reporting to Applicable Governmental Authorities and Public Disclosure

Within two (2) business days of receiving a report from a Regional Entity of a Possible Violation, Alleged Violation, or Confirmed Violation, NERC shall notify FERC of the Possible Violation, Alleged Violation or Confirmed Violation.

Where the report pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, NERC shall notify such other Applicable Governmental Authority, within two (2) business days of receiving a report of a Possible Violation, Alleged Violation or Confirmed Violation from the Regional Entity; provided, that NERC will not disclose any non-public U.S. compliance information that is subject to 18 C.F.R. §39.7(b)(4) to an Applicable Governmental Authority other than FERC without first obtaining permission from FERC for such disclosure and subject to any limitations placed by FERC on such disclosure. Likewise, NERC will not disclose non-public non-U.S. compliance information to an Applicable Governmental Authority (including FERC) without first obtaining permission from the Applicable Governmental Authority that has jurisdiction over the Registered Entity or portion of the Bulk Power System to which the non-public information pertains and subject to any limitations placed on such disclosure by such Applicable Governmental Authority or by other law of the applicable jurisdiction.

In any notice to, and request for permission to disclose compliance information from, FERC or another Applicable Governmental Authority pursuant to any provision of this Compliance Program, NERC will identify each Applicable Governmental Authority to which it proposes to disclose the information and the specific procedures that will be used for protecting from public disclosure any non-public compliance information that will be transferred to the other Applicable Governmental Authority or Authorities. The provisions of this paragraph do not apply to the provision by NERC to an Applicable Governmental Authority of information that is not directly related to a specific Registered Entity's compliance with a requirement of a Reliability Standard. NERC will publicly post on its website each Notice of Penalty, with any Critical Energy Infrastructure Information or other Confidential Information redacted (unless posting of the Critical Energy Infrastructure Information or Confidential Information has been determined to be permissible in accordance with Section 1500 of the Rules of Procedure), with the identity of the violator, together with any statement submitted by the Registered Entity, when NERC files the Notice of Penalty with FERC pursuant to Section 5.9.

NERC will provide reports quarterly to FERC and, where a report contains information pertaining to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority, on the status of all Possible, Alleged and Confirmed Violations for which mitigation activities have not been completed. All such reports to FERC and to other Applicable Governmental Authorities shall be provided in accordance with this Section.

9.0 DATA RETENTION AND CONFIDENTIALITY

9.1 Records Management

The Compliance Enforcement Authority records management policy shall provide for a routine and orderly process for the retention and disposal of electronic and paper records related to the Compliance Program, ensure verification of compliance with appropriate business, regulatory, and legal requirements and at a minimum conform to the data retention requirements of the Reliability Standards. The policy shall allow for the maintenance of records as required to implement the Compliance Program.

9.2 Retention Requirements

The Compliance Enforcement Authority records management policy will require that information and data generated or received pursuant to Compliance Program activities, including Compliance Audits, Self-Certifications, Spot Checks, Compliance Investigations, Self-Reports, Periodic Data Submittals, Exception Reporting, and Complaints, as well as a hearing process, will be retained for the longer of (i) five (5) years or (ii) any retention period specified in a Reliability Standard or by FERC or another Applicable Governmental Authority. The obligation to retain information and data commences upon the initiation of the Compliance Program activity that produces the data or information. If the information or data is material to the resolution of a controversy, the retention period for such data shall not commence until after the controversy is resolved.

Upon request from NERC, Regional Entities will provide to NERC copies of such information and data. NERC will retain the information and data in order to maintain a record of activity under the Compliance Program. In providing the information and data to NERC, the Regional Entity shall preserve any mark of confidentiality.

9.3 Confidentiality and Critical Energy Infrastructure Information

9.3.1 Definitions

Information or data generated or received pursuant to Compliance Program activities, including a hearing process, shall be treated in a confidential manner pursuant to the provisions of Section 1500 of the NERC Rules of Procedure. The terms "Confidential Information," "Confidential Business and Market Information," "Critical Energy Infrastructure Information," and "Critical Infrastructure" shall have the meanings stated in Appendix 2 to the NERC Rules of Procedure.

9.3.2 Protection of Confidential Information

The Compliance Enforcement Authority personnel (including any contractors, consultants and industry subject matter experts) and committee members, and participants in Compliance Program activities shall be informed of, and agree to comply with, Section 1500 of the NERC Rules of Procedure concerning Confidential Information.

9.3.3 Critical Energy Infrastructure Information

The Compliance Enforcement Authority will keep confidential all Critical Energy Infrastructure Information in accordance with Section 1500 of the NERC Rules of Procedures. Information deemed to be Critical Energy Infrastructure Information shall be redacted, in accordance with Section 1500 of the NERC Rules of Procedure, and shall not be released publicly.

ATTACHMENT 1

PROCESS FOR NON-SUBMITTAL OF REQUESTED DATA

FERC's regulations at 18 C.F.R §39.2(d) provide that each user, owner or operator of the Bulk Power System within the United States (other than Alaska and Hawaii) shall provide FERC, the ERO and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by FERC and set out in the rules of the ERO and each Regional Entity. In order to enforce this requirement, if data, information, or other reports (including Mitigation Plans) requested from a Registered Entity in connection with a compliance monitoring process or enforcement process are not received by the Required Date, the Compliance Enforcement Authority may sequentially execute the following steps for each Reliability Standard Requirement for which the Compliance Enforcement Authority has requested data, information, or other reports. However, upon a request from the Registered Entity submitted prior to the Required Date stating in reasonable detail the basis for the Registered Entity's need for additional time, the Compliance Enforcement Authority may afford the Registered Entity reasonable additional time to submit the data, information or report due to the scope or difficulty of the request or requirement for data, information or reports, the amount of the data, information or reports requested or required, or the form in which the data, information, or other reports has been requested or is required to be provided.

Step 1: The Compliance Enforcement Authority will issue a notification to the Registered Entity's designated contact for reliability matters, identifying the data, information or report that were requested or required and the Required Date and stating that the Required Date has passed and the Registered Entity should, within five (5) business days, either provide the data, information or report, or contact the Compliance Enforcement Authority with a proposed date by which the Registered Entity will provide the data, information or report. If the Compliance Enforcement Authority agrees with the Registered Entity on a revised date by which the Registered Entity will provide the data, information or report, the agreed revised date shall become the Revised Required Date.

Step2: If the Registered Entity does not provide a response to the notification in, and in accordance with, Step 1, within five (5) business days, or by a revised date as agreed to in Step 1, the Compliance Enforcement Authority will issue a notification to the Registered Entity's designated contact for reliability matters, with a copy to the Registered Entity's chief executive officer or equivalent, stating that if the data, information or report is not received within ten (10) business days, the Compliance Enforcement Authority may (i) implement a compliance monitoring process directed to the Registered Entity, or (ii) issue a Notice or other notification of Alleged Violation and Proposed Penalty or Sanction at the Severe Violation Severity Level to the Registered Entity for the Reliability Standard Requirement to which the requested or required

data, information or report relates.

Step 3: If the Registered Entity fails to produce the requested or required data, information or report in response to the notification in Step 2 within the ten (10) business day cure period set forth in the Step 2 notification, the Compliance Enforcement Authority may take any action of which the Registered Entity was notified in the Step 2 notification, including issuing a Notice or other notification of Alleged Violation and Proposed Penalty or Sanctionat the Severe Violation Severity Level for the Reliability Standard Requirement to which the requested or required data, information or report relates.

The process described in this Attachment 1 is intended to be applied where a Registered Entity does not respond by the Required Date to an initial request for data, information or reports in connection with a compliance monitoring and enforcement process and does not respond to subsequent requests (Steps 1 and 2 above) by the stated deadline. This process is not intended to apply where the Registered Entity responds, prior to the Required Date, to the initial request or requirement for data, information or reports with requests for clarification, definition of scope, or similar questions concerning the request or requirement for data, information or reports, or requests, prior to the Required Date, additional time to respond based on the scope or difficulty of the request or requirement for data, information or reports, the amount or extent of the data, information or reports requested or required, or the form in which the data, information or report is to be provided, and works with the Compliance Enforcement Authority in good faith to respond to the request or requirement for data, information or reports, as modified if appropriate by the Compliance Enforcement Authority based on questions raised by the Registered Entity.

ATTACHMENT 2 - HEARING PROCEDURES

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ATTACHMENT 2 - HEARING PROCEDURES

1.1 Applicability, Definitions and Interpretation

1.1.1 Procedure Governed

(a) The provisions set forth in this **Attachment 2** ("Hearing Procedures") shall apply to and govern practice and procedure before the Compliance Enforcement Authority in hearings in the United States conducted into:

(1) whether Registered Entities within the Compliance Enforcement Authority's Area of Responsibility have violated Reliability Standards, and

(2) if so, to determine the appropriate Mitigation Plans as well as any Remedial Action Directives, Penalties and/or sanctions in accordance with the NERC *Sanction Guidelines* and other applicable Penalty guidelines approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2).

(b) Any hearing conducted pursuant to these Hearing Procedures shall be conducted before a Hearing Officer and a Hearing Body established by the Compliance Enforcement Authority. Where the Hearing Body is comprised, in whole or in part, of industry stakeholders, the composition of the Hearing Body, after any recusals or disqualifications, shall be such that no two industry segments may control, and no single industry segment may veto, any decision by the Hearing Body on any matter brought before it for decision. Where the Hearing Body is comprised solely of independent members and an independent hearing Officer, decisions shall require a majority vote.

(c) The standard of proof in any proceeding under these Hearing Procedures shall be by a preponderance of the evidence. The burden of persuasion on the merits of the proceedings shall rest upon the Compliance Staff alleging noncompliance with a Reliability Standard, proposing a Penalty, opposing a Registered Entity's Mitigation Plan, or requiring compliance with a Remedial Action Directive.

(d) If a final order has been entered by the Hearing Body, or the Hearing Body has issued a ruling determining that there are no issues to be decided regarding the Alleged Violation, proposed Penalty amount, proposed Mitigation Plan or proposed Remedial Action Directive, or the Registered Entity and the Compliance Enforcement Authority have entered into a settlement agreement resolving the matters that are the subject of the hearing, the hearing shall be terminated by the Hearing Body and no further proceedings shall be conducted before the Hearing Body.

1.1.2 Deviation

To the extent permitted by law, any provision in these Hearing Procedures may be waived, suspended or modified by the Hearing Officer or the Hearing Body, for good cause shown, either upon the Hearing Officer's or the Hearing Body's own motion or upon the motion of any Participant.

1.1.3 Standards for Discretion

The Compliance Enforcement Authority's discretion under these Hearing Procedures shall be exercised to accomplish the following goals:

(a) Integrity of the Fact-Finding Process - The principal goal of the hearing process is to assemble a complete factual record to serve as a basis for a correct and legally sustainable ruling, decision or order.

(b) Fairness - Persons appearing in Compliance Enforcement Authority proceedings should be treated fairly. To this end, Participants should be given fair notice and opportunity to present explanations, factual information, documentation and legal argument. Action shall be taken as necessary to eliminate any disadvantage or prejudice to a Participant that would otherwise result from another Participant's failure to act diligently and in good faith.

(c) Independence - The hearing process should be tailored to protect against undue influence from any Person, Participant or interest group.

(d) Balanced Decision-Making - Decisions should be based solely on the facts and arguments of record in a proceeding and by individuals who satisfy the Compliance Enforcement Authority's conflict of interest policy.

(e) Impartiality - Persons appearing before the Hearing Body should not be subject to discriminatory or preferential treatment. Registered Entities should be treated consistently unless a reasonable basis is shown in any particular proceeding to depart from prior rulings, decisions or orders.

(f) Expedition - Proceedings shall be brought to a conclusion as swiftly as is possible in keeping with the other goals of the hearing process.

1.1.4 Interpretation

(a) These Hearing Procedures shall be interpreted in such a manner as will aid in effectuating the Standards for Discretion set forth in Section 1.1.3, and so as to require that all practices in connection with the hearings shall be just and reasonable.

(b) Any ruling, order or decision of the Hearing Officer referenced in these Hearing Procedures shall be made by the Hearing Body where the composition of the Hearing Body consists of independent members and an independent Hearing Officer.

(c) Unless the context otherwise requires, the singular of a term used herein shall include the plural and the plural of a term shall include the singular.

(d) To the extent that the text of a rule is inconsistent with its caption, the text of the rule shall control.

1.1.5 Definitions

Unless otherwise defined, as used in these Hearing Procedures, definitions in Appendix 2 of the NERC Rules of Procedure shall apply. For ease of reference, the following defined terms used in these Hearing Procedures are also set forth below:

"Clerk" shall mean an individual assigned by the Compliance Enforcement Authority to perform administrative tasks relating to the conduct of hearings as described in these Hearing Procedures.

"Compliance Enforcement Authority's Area of Responsibility" means the Compliance Enforcement Authority's Region. If a Regional Entity is the Compliance Enforcement Authority, the Compliance Enforcement Authority's Area of Responsibility is shown in Exhibit A to the delegation agreement between the Regional Entity and NERC.

"Critical Energy Infrastructure Information" means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that: (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

"Critical Infrastructure" means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

"Cyber Security Incident" means any malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.

"Director of Compliance" means the Director of Compliance of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority, who is responsible for the management and supervision of Compliance Staff, or his or her designee.

"Document" means, in addition to the commonly understood meaning of the term as information written or printed on paper, any electronically stored information, including writings, drawings, graphs, charts, photographs, sound recordings, images and other data or data compilations stored in any medium from which information can be obtained, and shall be translated by the producing party into reasonably usable form.

"ERO" or "Electric Reliability Organization" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the Bulk Power System in the United States, subject to Commission review. The organization may also have received recognition by Applicable Governmental Authorities in Canada and Mexico to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries.

"Evidentiary Hearing" means a hearing at which one or more Participants submits evidence for the record. A Testimonial Hearing is an Evidentiary Hearing, but an Evidentiary Hearing does not necessarily include the presentation of testimony by witnesses in person.

"FERC" means the Federal Energy Regulatory Commission.

"Hearing Body" means the body established or designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with these Hearing Procedures.

"Hearing Officer" means an individual employed or contracted by the Compliance Enforcement Authority and designated by the Compliance Enforcement Authority to preside over hearings conducted pursuant to these Hearing Procedures.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Body or by FERC to participate as an intervenor in a proceeding conducted pursuant to these Hearing Procedures, and as used in these Hearing Procedures shall include the members of the Compliance Staff of the Compliance Enforcement Authority that participate in a proceeding.

"Penalty" means and includes all penalties and sanctions, including but not limited to a monetary or non-monetary penalty; a limitation on an activity, function, operation or other appropriate sanction; or the addition of the Registered Entity or Respondent to a reliability watch list composed of major violators. Penalties must be within the range set forth in the NERC *Sanction Guidelines* approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2), and shall bear a reasonable relation to the seriousness of a Registered Entity's or Respondent's violation and take into consideration any timely efforts made by the Registered Entity or Respondent to remedy the violation.

"Person" means any individual, partnership, corporation, limited liability company, governmental body, association, joint stock company, public trust, organized group of persons, whether incorporated or not, or any other legal entity.

"Respondent" means the Registered Entity who is the subject of the Notice of Alleged Violation, contested Mitigation Plan or contested Remedial Action Directive that is the basis for the proceeding, whichever is applicable.

"Staff" or "Compliance Staff" means individuals employed or contracted by NERC or the Compliance Enforcement Authority who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties and Mitigation Plans.

"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies the Compliance Enforcement Authority's conflict of interest policy and is selected to assist in a proceeding by providing technical advice to the Hearing Officer and/or the Hearing Body.

"Testimonial Hearing" means an Evidentiary Hearing at which the witness or witnesses on behalf of one or more Participants appears in person to present testimony and be subject to cross-examination.

1.2 General Provisions including Filing, Service, Transcription and Participation

1.2.1 Contents of Filings

All filings made with the Hearing Body must contain:

(a) A caption that sets forth the title of the proceeding and the designated docket number or, if the filing initiates a proceeding, a space for the docket number;

(b) A heading that describes the filing and the Participant on whose behalf the filing is made;

(c) The full name, address, telephone number and email address of the Participant or the representative of the Participant making the filing;

(d) A plain and concise statement of any facts upon which the filing is based, which facts shall be supported by citations to the record of the hearing, if available, or other evidence; and

(e) The specific relief sought, which may be in the alternative, and the authority that provides for or otherwise allows the relief sought.

1.2.2 Form of Filings

(a) All filings shall be typewritten, printed, reproduced or prepared using a computer or other word or data processing equipment on white paper 8½ inches by 11 inches with inside text margins of not less than one inch. Page numbers shall be centered and have a bottom margin of not less than ½ inch. Line numbers, if any, shall have a left-hand margin of not less than ½ inch. The impression shall be on one side of the paper only and shall be double spaced; footnotes may be single spaced and quotations may be single spaced and indented.

(b) All pleadings shall be composed in either Arial or Times New Roman font, black type on white background. The text of pleadings or documents shall be at least 12-point. Footnotes shall be at least 10-point. Other material not in the body of the text, such as schedules, attachments and exhibits, shall be at least 8-point.

(c) Reproductions may be by any process provided that all copies are clear and permanently legible.

(d) Testimony prepared for the purpose of being entered into evidence shall include line numbers on the left-hand side of each page of text. Line numbers shall be continuous.

(e) Filings may include schedules, attachments or exhibits of a numerical or documentary nature which shall, whenever practical, conform to these requirements; however, any log,

graph, map, drawing, chart or other such document will be accepted on paper larger than prescribed in subparagraph (a) if it cannot be provided legibly on letter size paper.

1.2.3 Submission of Documents

(a) Where to File

Filings shall be made with the Clerk of the Compliance Enforcement Authority located at its principal office. The office will be open during the Compliance Enforcement Authority's regular business hours each day except Saturday, Sunday, legal holidays and any other day declared by the Compliance Enforcement Authority.

(b) When to File

Filings shall be made within the time limits set forth in these Hearing Procedures or as otherwise directed by the Hearing Officer or the Hearing Body. Filings will be considered made when they are date stamped received by the Clerk. To be timely, filings must be received no later 5:00 P.M. local time on the date specified.

(c) How to File

Filings may be made by personal delivery, mailing documents that are properly addressed with first class postage prepaid, or depositing properly addressed documents with a private express courier service with charges prepaid or payment arrangements made. Alternatively, filing by electronic means will be acceptable upon implementation of a suitable and secure system by the Compliance Enforcement Authority.

(d) Number of Copies to File

One original and five exact copies of any document shall be filed. The Clerk will provide each member of the Hearing Body with a copy of each filing.

(e) Signature

The original of every filing shall be signed by the Participant on whose behalf the filing is made, either by an attorney of the Participant or, by the individual if the Participant is an individual, by an officer of the Participant if the Participant is not an individual, or if the Participant is Staff, by a designee authorized to act on behalf of Staff.

(f) Verification

The facts alleged in a filing need not be verified unless required by these Hearing Procedures, the Hearing Officer or the Hearing Body. If verification is required, it must be under oath by a person having knowledge of the matters set forth in the filing. If any verification is made by an individual other than the signer, a statement must be included in or attached to the verification explaining why a person other than the signer is providing verification.

(g) Certificate of Service

Filings shall be accompanied by a certificate of service stating the name of the individuals served, the Participants whose interests the served individuals represent, the date on which service is made, the method of service and the addresses to which service is made. The certificate shall be executed by the individual who caused the service to be made.

1.2.4 Service

(a) Service List

For each proceeding, the Clerk shall prepare and maintain a list showing the name, address, telephone number, and facsimile number and email address, if available, of each individual designated for service. The Hearing Officer, Director of Compliance and the Registered Entity's compliance contact as registered with the Compliance Enforcement Authority, shall automatically be included on the service list. Participants shall identify all other individuals whom they would like to designate for service in a particular proceeding in their appearances or other filings. Participants may change the individuals designated for service in any proceeding by filing a notice of change in service list in the proceeding. Participants are required to update their service lists to ensure accurate service throughout the course of the proceeding. Copies of the service list may be obtained from the Clerk.

b) By Participants

Subject to the provisions of Section 1.5.10, any Participant filing a Document in a proceeding must serve a copy of the Document on each individual whose name is on the service list for the proceeding. Unless otherwise provided, service may be made by personal delivery, email, deposit in the United States mail properly addressed with first class postage prepaid, registered mail properly addressed with postage prepaid or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made.

(c) By the Clerk

The Clerk shall serve all issuances of the Hearing Officer and Hearing Body upon the members of the Hearing Body and each individual whose name is on the service list for the proceeding. Service may be made by personal delivery, email, deposit in the United States mail properly addressed with first class postage prepaid, registered mail properly addressed with postage prepaid or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made. The Clerk shall transmit a copy of the record of a proceeding to the ERO at the time the Compliance Enforcement Authority transmits to the ERO either (1) a Notice of Penalty, or (2) a Hearing Body final order that includes a Notice of Penalty.

(d) Effective Date of Service

Service by personal delivery or email is effective immediately. Service by mail or registered mail is effective upon mailing; service by a private express courier service is effective upon delivery to the private express courier service. Unless otherwise provided, whenever a Participant has the right or is required to do some act within a prescribed period after the service

of a document upon the Participant, four (4) days shall be added to the prescribed period when the document is served upon the Participant by mail or registered mail.

1.2.5 Computation of Time

The time in which any action is required to be done shall be computed by excluding the day of the act or event from which the time period begins to run, and by including the last day of the time period, unless the last day is a Saturday, Sunday, legal holiday or any other day upon which the office of the Compliance Enforcement Authority is closed, in which event it also shall be excluded and the date upon which the action is required shall be the first succeeding day that is not a Saturday, Sunday, legal holiday, or day upon which the office of the Compliance Enforcement Authority is closed.

1.2.6 Extensions of Time

Except as otherwise provided by law, the time by which a Participant is required or allowed to act may be extended by the Hearing Officer or Hearing Body for good cause upon a motion made before the expiration of the period prescribed. If any motion for extension of time is made after the expiration of the period prescribed, the Hearing Officer or Hearing Body may permit performance of the act if the movant shows circumstances sufficient to justify the failure to act in a timely manner.

1.2.7 Amendments

Amendments to any documents filed in a proceeding may be allowed by the Hearing Officer or the Hearing Body upon motion made at any time on such terms and conditions as are deemed to be just and reasonable.

1.2.8 Transcripts

(a) A full and complete record of all hearings, including any oral argument, shall be transcribed verbatim by a certified court reporter, except that the Hearing Officer may allow off-the-record discussion of any matter provided the Hearing Officer states the ruling on any such matter, and the Participants state their positions or agreement in relation thereto, on the record. The court reporter shall file a copy of each transcript with the Clerk. Upon receipt of a transcript from the court reporter, the Clerk shall send notice to the Participants stating that a transcript has been filed by the court reporter, the date or dates of the hearing that the transcript records, and the date the transcript was filed with the Clerk.

(b) Unless otherwise prescribed by the Hearing Officer, a Participant may file and serve suggested corrections to any portion of a transcript within fourteen (14) days from the date of the Clerk's notice that the transcript has been filed with the Clerk, and any responses shall be filed within ten (10) days after service of the suggested corrections. The Hearing Officer shall determine what changes, if any, shall be made, and shall only allow changes that conform the transcript to the statements being transcribed and ensure the accuracy of the record.

(c) The Compliance Enforcement Authority will pay for transcription services, for a copy of the transcript for the record and for a copy of the transcript for Staff. Any other Participant shall pay for its own copy of the transcript if it chooses to obtain one and, should any Participant seek to obtain a copy of the transcript on an expedited basis, it shall pay for the expedited transcription services.

1.2.9 Rulings, Notices, Orders and Other Issuances

Any action taken by the Hearing Officer or the Hearing Body shall be recorded in a ruling, notice, order or other applicable issuance, or stated on the record for recordation in the transcript, and is effective upon the date of issuance unless otherwise specified by the Hearing Officer or the Hearing Body. All notices of hearings shall set forth the date, time and place of hearing.

1.2.10 Location of Hearings and Conferences

All hearings and oral arguments shall be held at the principal office of the Compliance Enforcement Authority unless the Hearing Officer or Hearing Body designates a different location.

1.2.11 Participant Participation

Participants may appear at any hearing via teleconference subject to the approval of the Hearing Officer and, in the event of oral argument, the Hearing Body, except as required by Section 1.6.6. Staff may participate and be represented by counsel in hearings, and shall have the rights and duties of any Participant.

1.2.12 Interventions

(a) The Respondent(s) and Staff shall be Participants to the proceeding. Unless otherwise authorized by the Hearing Body or by FERC, no other Persons shall be permitted to intervene or otherwise become a Participant to the proceeding.

(b) The Hearing Body may allow a Person to intervene only if the Hearing Body determines that the Person seeking intervention has a direct and substantial interest in the outcome of the Alleged Violation, proposed Penalty or sanction, Mitigation Plan, or Remedial Action Directive that is the subject of the proceeding. Examples of a direct and substantial interest in the outcome shall include

(1) that the Person seeking intervention has received a Notice of Alleged Violation or a Remedial Action Directive involving the same Reliability Standard requirement(s) and arising out of the same event or occurrence as the existing Respondent(s) that is the subject of the proceeding, or

(2) that the Person seeking intervention will or may be contractually or legally liable to the original Respondent(s) for payment of all or a portion of the proposed Penalty or sanction that is the subject of the proceeding, provided, that after the Person seeking intervention sufficiently demonstrates it will or may be contractually or legally liable for payment of all or a portion of the proposed Penalty or sanction to be granted intervention, the Person granted intervention and

the existing Respondents will not be allowed to litigate in the proceeding whether the Person granted intervention is contractually or legally liable for payment of all or a portion of the proposed Penalty or sanction or the amount of the proposed Penalty or Sanction for which the Person granted intervention is or may be liable.

That the Person seeking intervention has received a Notice of Alleged Violation for the same Reliability Standard Requirement(s) as the original Respondent(s) but arising out of a different event or occurrence; or seeks to intervene to advocate an interpretation of the Reliability Standard Requirement(s) or provision(s) of the *Sanction Guidelines*, that are at issue in the proceeding, without more, shall not constitute a direct and substantial interest in the outcome and shall not be grounds on which the Hearing Body may allow the Person to intervene.

(c) A Person seeking intervention shall do so by filing a motion to intervene with the Clerk. The motion shall state the Person's interest in sufficient factual detail to demonstrate that the Person should be allowed to intervene pursuant to Section 1.2.12(b). The motion to intervene shall also state the Person's agreement to maintain the confidential and non-public nature of the hearing, including all pleadings and other Documents filed or exchanged in connection with the request for intervention. Any facts alleged in, or offers of proof made in, the motion to intervene shall be supported by affidavit or verification.

(d) The Clerk shall promptly provide copies of the motion to intervene to the Hearing Officer and the Participants. The Hearing Officer shall promptly set a time period, not to exceed seven (7) days, within which the Participants may file responses to the motion to intervene. Within seven (7) days following the end of the response period, the Hearing Officer shall issue a recommendation to the Hearing Body as to whether or not the motion to intervene should be granted.

(e) The Hearing Body may, within seven (7) days following the date of the Hearing Officer's recommendation, issue a decision granting or denying the motion to intervene. If the Hearing Body does not issue a decision granting or denying the motion to intervene within seven (7) days following the date of the Hearing Officer's recommendation, the Hearing Officer's recommendation shall become the decision of the Hearing Body and the motion to intervene shall be deemed granted or denied by the Hearing Body in accordance with the Hearing Officer's recommendation.

(f) The Hearing Officer, on motion of a Participant or on his or her own motion, or the Hearing Body, on recommendation by the Hearing Officer or its own motion, may stay or suspend the proceeding while a request to intervene, including a request to intervene filed directly with FERC, and including any appeal of the grant or denial of the request to intervene, is being resolved.

(g) A Person allowed to intervene and become a Participant to a proceeding shall be designated as a Respondent and deemed to be aligned with the existing Respondent(s), unless the Hearing Body, in the decision granting intervention, states that the Person allowed to intervene shall be deemed to be aligned with another Participant to the proceeding.

(h) A Person allowed to intervene and become a Participant to a proceeding is required to take the record and the procedural status of the proceeding as it stands on the date the Person's motion to intervene is granted by the Hearing Body.

(i) A Person may appeal a decision of the Hearing Body denying the Person's motion to intervene, and the Compliance Staff, the Respondent or any other Participant may appeal a decision granting or denying a motion to intervene, in accordance with Section 414 of the NERC Rules of Procedure. A notice of appeal shall be filed with the NERC director of enforcement no later than seven (7) days following the date of the decision of the Hearing Body granting or denying the motion to intervene.

1.2.13 Proceedings Closed to the Public

No hearing, oral argument or meeting of the Hearing Body shall be open to the public, and no notice, ruling, order or any other issuance of the Hearing Officer or Hearing Body, or any transcript, made in any proceeding shall be publicly released unless the ERO (within the U.S., in accordance with the authorization previously granted by FERC to release information about a non-public proceeding) or FERC (in the case of U.S.-related information) or another Applicable Governmental Authority (in the case of non-U.S.-related information) determine that public release is appropriate. Only the members of the Hearing Body, the Participants, the Hearing Officer and the Technical Advisors, if any, shall be allowed to participate in or obtain information relating to a proceeding.

1.2.14 Docketing System

The Clerk shall maintain a system for docketing proceedings. A docketed proceeding shall be created upon the filing of a request for a hearing. Unless NERC provides a different docketing system that will be used uniformly by the Compliance Enforcement Authorities, docket numbers shall be assigned sequentially beginning with a two digit number that relates to the last two digits of the year in which the docket is initiated, followed by a dash ("-"), followed by the letters "[RE]", followed by a dash ("-"), followed by a four digit number that will be "0001" on January 1 of each calendar year and ascend sequentially until December 31 of the same calendar year.

1.2.15 Representations Deemed to be Made in All Pleadings

A Participant presenting any pleading to the Hearing Officer or Hearing Body shall be deemed to certify that to the best of the Participant's knowledge, information and belief, formed after and based on an inquiry that is reasonable under the circumstances:

(a) the factual allegations set forth in the pleading have or will have support in the evidence or the Participant believes they will have support in the evidence after reasonable opportunity for further investigation or discovery;

(b) the denials in the pleading of factual allegations made by another Participant are warranted by or will be warranted by the evidence or, if specifically so identified, are reasonably based on belief or on a lack of information;

(c) the claims, defenses and other contentions set forth in the pleading are warranted based on the applicable Reliability Standard Requirement(s) or Rules of Procedure provisions; and

(d) the pleading is not being presented for any improper purpose, such as to harass, cause unnecessary delay, or needlessly increase the cost of the hearing or the cost incurred by any Participant.

1.2.16 Hold Harmless

A condition of a Participant invoking these Hearing Procedures and participating in a hearing is that the Participant agrees that the Compliance Enforcement Authority, including without limitation its members, board of directors or trustees, compliance committee, any other committees or subcommittees, Staff, contracted employees, Hearing Body members, Hearing Officers and Technical Advisors, shall not be liable, and shall be held harmless against the consequences of, or any action or inaction arising out of, the hearing process, or of any agreement reached in resolution of a dispute or any failure to reach agreement as a result of a proceeding. This "hold harmless" provision does not extend to matters constituting gross negligence, intentional misconduct or breach of confidentiality.

1.3 Initiation of the Hearing Process

1.3.1 Registered Entity's Option to Request a Hearing

(a) Except when contesting a Remedial Action Directive pursuant to Section 1.9 of these Hearing Procedures, a Registered Entity may file a statement, in accordance with Section 1.3.1(e), with the Compliance Enforcement Authority requesting a hearing if either:

(1) The Registered Entity files a response to a Notice of Alleged Violation that contests either the Alleged Violation, the proposed Penalty, or both; or

(2) The Compliance Staff submits to the Registered Entity a statement rejecting the Registered Entity's proposed revised Mitigation Plan submitted after Compliance Staff rejected the Registered Entity's initial proposed Mitigation Plan.

(b) A Registered Entity must file its hearing request within forty (40) days after

(1) the Registered Entity files its response to the Notice of Alleged Violation; or

(2) the Compliance Staff submits to the Registered Entity its statement identifying a disagreement with the Registered Entity's proposed Mitigation Plan, whichever is applicable.

(c) If the Registered Entity does not file a hearing request within the time period set forth in this Section, then the Registered Entity will be deemed to have agreed and waived any objection to the proposed Penalty, the Alleged Violation or the Compliance Staff's rejection of the revised Mitigation Plan, whichever is applicable.

(d) In accordance with Section 5.3 of the Compliance Program, a Notice of Alleged Violation issued to a Registered Entity or a Staff statement setting forth its rejection of a Registered Entity's proposed revised Mitigation Plan shall clearly state that the Registered Entity has the option to contest the Alleged Violation, proposed Penalty, or both, or the Compliance Staff's rejection of the proposed revised Mitigation Plan, using either the shortened hearing procedure pursuant to Section 1.3.4 or the general hearing procedure described in Sections 1.4 to 1.7.

(e) The Registered Entity's statement requesting a hearing shall:

(1) contain a plain and concise statement of the facts and arguments supporting the Registered Entity's position, as applicable, that it did not violate the Reliability Standard Requirement(s) set forth in the Notice of Alleged Violation, that the proposed Penalty or sanction is too high and should be reduced, or that the Registered Entity's proposed Mitigation Plan should be approved;

(2) state the relief that the Registered Entity requests the Hearing Body to grant; and

(3) state whether the Registered Entity requests the shortened hearing procedure or the general hearing procedure.

The Registered Entity's statement may set forth two or more alternative grounds on which the Registered Entity bases its position, as applicable, that it did not violate the Reliability Standard Requirement(s) set forth in the Notice of Alleged Violation, that the proposed Penalty or sanction is too high and should be reduced, or that the Registered Entity's proposed Mitigation Plan should be approved.

(f) If the Registered Entity (or any Respondent if there are more than one Respondent) requests the general hearing procedure, the general hearing procedure shall apply. If the Registered Entity (or all Respondents if there are more than one Respondent) requests the shortened hearing procedure, Compliance Staff and any other Participants shall submit a filing within five (5) days of the Registered Entity's hearing request that states whether Staff or such other Participant agrees to use the shortened hearing procedure. If Staff or another Participant makes a filing requesting the general hearing procedure, then the general hearing procedure shall apply; otherwise the shortened hearing procedure requested by the Registered Entity or Entities shall be used. Once either the general or shortened hearing procedure has been selected, the Participants shall not be allowed to revert to the non-selected hearing procedure unless the Participants mutually agree.

(g) A Registered Entity shall attach to a request for hearing whichever of the following are applicable:

(1) The Registered Entity's Self-Report of a violation;

(2) The Notice of Alleged Violation and the Registered Entity's response thereto; and/or

(3) The Registered Entity's proposed revised Mitigation Plan and the Compliance Staff's statement rejecting the proposed revised Mitigation Plan.

1.3.2 Compliance Staff's Response to Request for Hearing

(a) If the Registered Entity's request for hearing requests that the shortened hearing procedure be used, the Compliance Staff shall file a response stating whether it agrees to the use of the shortened hearing procedure.

(b) If the Registered Entity's request for hearing requests that the Registered Entity's proposed revised Mitigation Plan should be approved, the Compliance Staff shall file a response stating the Compliance Staff's position as to why the Registered Entity's proposed revised Mitigation Plan should not be approved and setting forth any additional terms that the Compliance Staff believes should be included in the Mitigation Plan.

(c) If the Registered Entity's request for hearing does not request that the shortened hearing procedure be used and does not request that the Registered Entity's proposed revised Mitigation Plan should be approved, the Compliance Staff may, but is not required to, file a response stating, as applicable, the basis for the Compliance Staff's position that the Registered Entity violated the Reliability Standard Requirement(s) specified in the Notice of Alleged Violation or that the proposed Penalty or sanction is appropriate under the *Sanction Guidelines* and should not be reduced.

(d) Any response by the Compliance Staff required or permitted by this Section shall be filed within fifteen (15) days after the date the request for hearing was filed, unless the Hearing Officer or Hearing Body allows a longer time to file the response.

1.3.3 Notice of Hearing

(a) The Clerk shall issue a notice of hearing not less than sixteen (16) days, and not more than twenty-one (21) days, after the Registered Entity files its request for hearing.

(b) The notice of hearing shall state whether the shortened hearing procedure or the general hearing procedure will be used.

(c) The notice of hearing shall identify the Hearing Officer and the date, time and place for the initial prehearing conference.

(1) If the shortened hearing procedure is to be used, the initial prehearing conference shall be set for a date within seven (7) days following the date of the notice of hearing.

(2) If the general hearing procedure is to be used, the initial prehearing conference shall be set for a date within fourteen (14) days following the date of the notice of hearing.

1.3.4 Shortened Hearing Procedure

The shortened hearing procedure shall be as set forth in this Section. The rules applicable to the general hearing procedure shall apply to the shortened hearing procedure unless the context of such a rule is inconsistent with the procedure set forth in this Section or otherwise renders it inapplicable to the shortened hearing procedure. The rules concerning ex parte communications

in Section 1.4.7 are hereby expressly made applicable to the shortened hearing procedure under this Section.

The Hearing Body shall utilize a Hearing Officer to preside over the shortened hearing procedure in accordance with Section 1.4.2. But, no Testimonial Hearing will be held in the shortened hearing procedure and the Participants will not present witness testimony or file briefs, except that briefs on exceptions and briefs in reply to exceptions may be allowed pursuant to subsection (g). Instead, the following events shall take place within the following periods:

(a) The initial prehearing conference shall be held within seven (7) days after the date on which the notice of hearing is issued. In addition to any other matters set forth in Section 1.5.2 that may apply, the initial prehearing conference will be used to develop a schedule for the preparation and submission of comments in accordance with subsections (c) through (e).

(b) Within ten (10) days after the date on which the notice of hearing is issued, Staff shall make Documents available to the Registered Entity for inspection and copying pursuant to Section 1.5.7.

(c) Within twenty-one (21) days after the initial prehearing conference, the Staff shall file:

(1) initial comments stating Staff's position on all issues and the rationale in support of its position, including all factual and legal argument;

(2) all Documents that Staff seeks to introduce in support of its position that have not already been submitted in the proceeding; and

(3) a verification attesting to the truthfulness of the facts alleged in the filing.

(d) Within fourteen (14) days of Staff's initial comment filing pursuant to subsection (c), the Registered Entity shall file:

(1) responsive comments stating the Registered Entity's position on all issues and the rationale in support of its position, including all factual and legal argument, which comment also may respond to Staff's initial comments;

(2) all Documents that the Registered Entity seeks to introduce in support of its position that have not already been submitted in the proceeding; and

(3) a verification attesting to the truthfulness of the facts alleged in the filing.

(e) Within seven (7) days after the Registered Entity's responsive comment filing pursuant to subsection (d), Staff shall file reply comments that shall be limited in scope to responding to the Registered Entity's responsive comments and be supported by a verification attesting to the truthfulness of the facts alleged in the filing. Staff shall not submit any additional Documents in support of its position as part of this filing except upon motion and good cause shown. If Staff is allowed to file additional Documents in support of its position based upon such a

motion, the Registered Entity shall have the right to file additional Documents in support of its position that are responsive to the additional Documents that Staff is allowed to file provided that any additional Registered Entity filing also shall be verified.

(f) The Hearing Officer shall issue an initial opinion within twenty-one (21) days after the Staff's reply comments filing or any additional filing by the Registered Entity pursuant to subsection (e).

(g) If either Participant requests, the Hearing Officer shall allow each Participant to file, within seven (7) days after the Hearing Officer's initial opinion, exceptions to the Hearing Officer's initial opinion in a brief designated "brief on exceptions" in accordance with Section 1.7.5 and within seven (7) days thereafter, a reply brief designated "brief in reply to exceptions."

(h) The Hearing Body shall strive, but is not required, to issue a final order within one hundred twenty (120) days of the notice of hearing.

The Hearing Officer or Hearing Body may modify any time period set forth within this Paragraph as warranted by the circumstances but it will be the objective of the Hearing Body to issue the final order within one hundred twenty (120) days of the notice of hearing.

1.4 General Hearing Procedure

1.4.1 [Intentionally Left Blank]

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1.4.2 Hearing Officer

(a) The Compliance Enforcement Authority shall utilize a Hearing Officer to preside over each hearing conducted pursuant to these Hearing Procedures, provided that the Hearing Officer's actions shall be subject to the authority of the Hearing Body as set forth in Section 1.4.3. Members of the Hearing Body may attend any aspect of the hearing.

(b) The Hearing Officer is responsible for the conduct of the hearing, including administering the hearing from the initial prehearing conference through the issuance of the Hearing Officer's initial opinion, any administrative hearing functions thereafter, and submission of the matter to the Hearing Body for final decision through the presentation to the Hearing Body of an initial opinion. The Hearing Officer shall have those duties and powers necessary to those ends, consistent with and as further enumerated in these Hearing Procedures, including the following:

(1) To administer oaths and affirmations;

(2) To schedule and otherwise regulate the course of the hearing, including the ability to call to recess, reconvene, postpone or adjourn a hearing;

(3) Consistent with any timing or deadline requirements imposed by these Hearing Procedures or by applicable law, to separate any issue or group of issues from other issues in a proceeding and treat such issue(s) as a separate phase of the proceeding;

(4) Consistent with any timing or deadline requirements imposed by these Hearing Procedures or by applicable law, to modify any time period, if such modification is in the interest of justice and will result in no undue prejudice to any other Participant;

(5) To supervise and issue orders concerning discovery;

(6) To conduct prehearing conferences, status hearings and Evidentiary Hearings;

(7) To hear argument on all objections, motions and other requests, and to rule upon all objections, motions and other requests that do not result in the final determination of the proceeding;

(8) To rule on and receive evidence;

(9) To call upon a Participant to produce further evidence that is material and relevant to any issue;

(10) To issue protective orders pursuant to Section 1.5.10;

(11) To issue initial opinions; and

(12) To ensure that hearings are conducted in a full, fair and impartial manner, that order is maintained and that unnecessary delay is avoided in the disposition of the proceedings.

(c) The Compliance Enforcement Authority shall disclose the employment history and professional affiliations of the Hearing Officer within two (2) days of the Hearing Officer's assignment to the proceeding, and Participants to the hearing may raise objections to the Hearing Officer's participation in accordance with Section 1.4.5.

1.4.3 Hearing Body

(a) The composition of the Hearing Body, after any recusals or disqualifications, shall be such that no two industry segments may control, and no single industry segment may veto, any decision of the Hearing Body on any matter brought before it for decision.

(b) The Hearing Body is vested with the authority to issue a final order resolving the issue(s) in all cases. To that end:

(1) Upon receiving a filing by a Participant, the Clerk shall promptly send a notice to the members of the Hearing Body identifying the date of the filing and the Participant making the filing and briefly describing the nature of the filing. Any member of the Hearing Body may request of, and shall receive from, the Clerk, a

copy of any filing by a Participant. The Hearing Body shall not receive Documents made available by Staff for inspection and copying by the Respondent, or other responses to discovery between the Participants, unless such Documents are placed into the record pursuant to Section 1.6.7.

(2) The Clerk shall send all issuances of the Hearing Officer to the members of the Hearing Body.

(3) The Hearing Body or any individual member thereof may, but is not required to, attend any prehearing conference, status hearing or Evidentiary Hearing, and/or to submit questions to the Hearing Officer to submit to a Participant or any witness at any hearing. At any prehearing conference or hearing attended by a member of the Hearing Body, any member of the Hearing Body may ask questions directly of any Participant or witness.

(4) The Hearing Body shall have the same authority as the Hearing Officer, as set forth in these Hearing Procedures, to require the Participants or any individual Participant to: (i) address a specific issue in testimony, evidence or briefs; (ii) present oral argument on an issue; (iii) file pre-Evidentiary Hearing memorandums; or (iv) produce further evidence that is material and relevant to any issue. To this end, the Hearing Body shall be entitled to issue questions or requests for information to any Participant or any witness at any time until the issuance of a final order.

(5) To the extent that the Hearing Body disagrees with any issuance or ruling of the Hearing Officer, it may, on its own motion or upon petition for interlocutory review meeting the requirements of Section 1.4.4, reverse or modify the issuance or ruling in whole or in part, or take any other action as may be appropriate.

(6) The Hearing Body shall resolve the issue(s) in every hearing through the issuance of a final order. In issuing a final order, the Hearing Body shall consider the Hearing Officer's initial opinion but shall have the authority to reject, modify or approve the initial opinion in whole or in part.

1.4.4 Interlocutory Review

(a) A Participant shall be allowed to seek interlocutory review by the Hearing Body of any ruling of the Hearing Officer where the ruling for which interlocutory review is sought presents an extraordinary circumstance which makes prompt review necessary to prevent prejudice to a Participant's ability to present its position in the proceeding. Failure to seek such review shall not operate as a waiver of any objection to such ruling.

(b) Unless good cause is shown or unless otherwise ordered by the Hearing Officer or the Hearing Body, the Participant seeking review shall file a petition for interlocutory review within fourteen (14) days after the date of the action that is the subject of the petition. The petition shall contain, in a separately identified section, a demonstration that the ruling for which interlocutory review is sought presents an extraordinary circumstance which makes prompt review necessary to prevent prejudice to the Participant's ability to present its position in the proceeding. The

petition shall be filed with any offer of proof and supported by references to the record, or by affidavit if based on facts that do not appear in the record. Responses to petitions for interlocutory review shall be filed within seven (7) days after service of the petition. No replies to responses shall be allowed.

(c) The Hearing Officer shall file a report to the Hearing Body within fourteen (14) days from the filing of the petition. The Hearing Officer's report shall set forth the relevant facts and other background information relating to the ruling on which interlocutory review is sought, the basis for the Hearing Officer's ruling, a summary of the Participants' arguments on the petition for interlocutory review, and the recommendation of the Hearing Officer for the disposition of the petition by the Hearing Body.

(d) On review of a Hearing Officer's ruling, the Hearing Body may affirm or reverse the ruling in whole or in part, and may take any other just and reasonable action with respect to the ruling, such as declining to act on an interlocutory basis. The Hearing Body may reject the petition for interlocutory review on the grounds that the ruling for which review is sought does not present an extraordinary circumstance which makes prompt review necessary to prevent prejudice to a Participant's ability to present its position in the proceeding, without considering or ruling on the substance of the petitioner's arguments.

(e) Issuance of a ruling on a petition for interlocutory review shall require (i) a quorum (as defined in Section 1.7.8) of the Hearing Body, and (ii) majority vote of the members of the Hearing Body voting on the final order (which number of members voting shall not be less than a quorum). Petitions to rehear or reconsider the Hearing Body's action taken on interlocutory review shall not be allowed. Filing and disposition of a petition for interlocutory review of a ruling of the Hearing Officer shall not suspend or otherwise delay a hearing or any other scheduled dates in the proceeding except as authorized by the Hearing Officer or the Hearing Body based on a finding of exceptional circumstances.

(f) A non-Participant that has been ordered by the Hearing Officer pursuant to Section 1.5.8 to produce or provide Documents, information or testimony, and has failed to obtain the relief sought from the Hearing Officer through filing objections to or a motion to quash the order, shall also be entitled to seek interlocutory review by the Hearing Body of the Hearing Officer's order, with respect to (i) whether the non-Participant is within the class of Persons subject to such orders pursuant to Section 1.5.8, and (ii) the reasonableness of the Hearing Officer's order to produce or provide Documents, information or testimony.

1.4.5 Disqualification

(a) A Hearing Officer, Technical Advisor or member of the Hearing Body shall recuse himself or herself from a proceeding if participation would violate the Compliance Enforcement Authority's applicable conflict of interest policy.

(b) Any Participant may file a motion to disqualify or for recusal of a Hearing Officer, Technical Advisor or member of the Hearing Body from a proceeding on grounds of a conflict of interest, an ex parte communication prohibited by section 1.4.7, or the existence of other circumstances that could interfere with the impartial performance of his or her duties. The Participant shall set forth and support its alleged grounds for disqualification by affidavit. A

motion for disqualification shall be filed within fifteen (15) days after the later of: (1) the time when the Participant learns of the facts believed to constitute the basis for disqualification; or (2) the time when the Participant is notified of the assignment of the Hearing Officer or Technical Advisor.

(c) The Hearing Officer shall issue a proposed ruling for the Hearing Body's consideration upon the filing of a motion for disqualification unless the Hearing Officer is the subject of the motion. The Hearing Body, without the participation of any member who is the subject of the motion, shall issue a final ruling on the motion. If the Hearing Officer recuses himself or herself or is disqualified, the Hearing Body will appoint a replacement Hearing Officer. To ensure fairness to the Participants and expedite completion of the proceeding when a replacement Hearing Officer is appointed after a hearing has commenced, the replacement Hearing Officer may recall any witness or may take other steps necessary to ensure familiarity with any part or all of the record.

(d) If a quorum (as defined in Section 1.7.8) of the Hearing Body does not remain after any recusals and rulings on motions for disqualification, then the Compliance Enforcement Authority shall appoint at least the number of new members to the Hearing Body necessary to create a quorum. The new member(s) shall serve on the Hearing Body through the conclusion of the proceeding but not thereafter. Any new member of the Hearing Body shall be subject to the provisions applicable herein to all Hearing Body members.

1.4.6 Technical Advisor

(a) The Hearing Officer and/or the Hearing Body may elect to use one or more Technical Advisors to assist in any proceeding. Such an election may be made at any time during the course of a proceeding. Any Staff member who serves as a Technical Advisor shall not have been involved in or consulted at any time in regard to any Compliance Staff investigation, determination of a Possible Violation, Alleged Violation or Penalty, or assessment of a Registered Entity's proposed Mitigation Plan that resulted in the proceeding in which technical advice would be rendered, and shall not be a member of Staff participating in the proceeding on which such technical advice would be rendered.

(b) If the Hearing Officer or Hearing Body uses a Technical Advisor to assist in any hearing, the Hearing Officer or Hearing Body shall disclose the identity, employment history and professional affiliations of the Technical Advisor within two (2) days of the Technical Advisor's assignment to the proceeding, and Participants to the hearing may raise objections to the Technical Advisor's participation in accordance with Section 1.4.5.

1.4.7 No Ex Parte Communications

(a) Once a Registered Entity requests a hearing pursuant to Section 1.3.1:

(1) neither the Hearing Body, the Hearing Officer, nor the Technical Advisor(s), if any, may communicate either directly or indirectly with any Person concerning any issue in the proceeding outside of the hearing process; except that

(2) the Hearing Body, the Hearing Officer, and the Technical Advisor(s), if any, may communicate outside of the hearing process either directly or indirectly with a Participant or a Participant's representative:

(A) in writing if the writing is simultaneously provided to all Participants; or

(B) orally if a representative for every Participant is present in person or by telephone;

(C) subject to the requirement that the substance of any ruling on any issue discussed shall be memorialized on the record or by the issuance of a notice or ruling, and that any Participant objecting to the ruling shall have the opportunity to state its objection on the record.

(b) Exceptions

(1) The proscription in subsection (a)(1) does not prohibit members of the Compliance Staff from communicating with the Registered Entity, and representatives, agents or employees thereof on any topic, provided that any member of the Compliance Staff involved in any such communication relating to the subject matter of the proceeding may not be, and may not subsequently serve as, a Technical Advisor.

(2) The proscription in subsection (a)(1) does not prohibit communications between or among members of the Hearing Body, the Hearing Officer and any Technical Advisor.

(3) The proscription in subsection (a)(1) does not prohibit communications between the Hearing Officer or members of the Hearing Body to the Clerk for the purpose of transmitting documents, giving instructions to the Clerk, or discussing scheduling and other procedural matters relating to the proceeding.

(4) The proscription in subsection (a)(1) does not prohibit communications between or among the Clerk, the Hearing Body and representatives of the Compliance Enforcement Authority for purposes of establishing the hearing forum.

(c) Any member of the Hearing Body, the Hearing Officer or any Technical Advisor who receives or who makes or knowingly allows a communication prohibited by this Section shall, within seven (7) days of the communication, file and serve on the Participants in the proceeding a notice of ex parte communication setting forth the date, time and place of communication, a summary of the substance and nature of the communication and all responses thereto, and a list of each Person who made or received the communication and, if the communication or any response thereto was in writing, a copy of the written communication shall be attached.

1.4.8 Appearances

(a) Participants shall file written appearances within seven (7) days after the notice of hearing is issued. A Participant's written appearance shall identify the name(s) of each

individual authorized to represent the Participant in the proceeding exclusive of witnesses. An individual may appear on his or her own behalf. A corporation, limited liability company, association, partnership or governmental body may appear by any bona fide officer or designee who has the authority to act on behalf of the Participant. A Participant also may appear by an attorney.

(b) A Participant's written appearance shall state, with respect to each individual that the Participant identifies for service, the individual's name, address, telephone number, and facsimile number and email address, if available, where service shall be made.

A Participant may withdraw any individual from the Participant's representation or otherwise change the identity of individuals authorized to represent the Participant in a proceeding by filing a notice of a change in service list.

(c) Any attorney appearing on behalf of a Participant shall be licensed to practice law and in good standing before the Supreme Court of the United States or the highest court of any State, territory of the United States or the District of Columbia. All representatives appearing before the Hearing Body or Hearing Officer shall conform to the standards of ethical conduct required of practitioners before the courts of the United States.

(d) Individuals representing Participants in any hearing also shall enter their appearances at the beginning of the hearing by stating their names, addresses, telephone numbers and email addresses orally on the record.

1.4.9 Failure to Appear or Exercise Diligence

The failure of any Participant to appear during any hearing without good cause and without notification may be grounds for dismissal or deciding against the interests of such Participant.

1.4.10 Consolidation of Proceedings

(a) In the event that more than one Registered Entity receives a Notice of Alleged Violation for the same event or occurrence, and each Registered Entity selects the general hearing procedure described in Sections 1.4 to 1.7, the Hearing Body on its own motion or on motion of a Participant may exercise its discretion to examine the actions of all such Registered Entities in a single proceeding as long as an initial opinion has not been rendered by the Hearing Officer pursuant to Section 1.7.4 in any proceeding to be consolidated.

(b) A Participant may file a motion to consolidate into a single proceeding Alleged Violations of different Reliability Standards against a single Respondent, and related contests of Penalties or Mitigation Plans, arising out of the same event or occurrence. Such consolidation may be allowed in the discretion of the Hearing Officer or Hearing Body, as applicable.

1.5 Prehearing Procedure

1.5.1 [Intentionally left blank]

1.5.2 Prehearing Conference

(a) The Hearing Officer shall hold at least one prehearing conference, which may be the initial prehearing conference or a subsequently scheduled prehearing conference, for the following purposes:

(1) Preliminarily identify the issues and discuss the anticipated form of the hearing;

(2) Discuss a schedule for any discovery to be conducted and address any discovery issues that are raised at that time;

(3) Explore the possibility of obtaining admissions of fact and of the authenticity of Documents that would avoid unnecessary proof;

(4) Develop a schedule for the preparation and submission of evidence and witness testimony, including the disclosure of witnesses and exhibits and whether the use of pre-filed testimony may not be appropriate, in advance of the Evidentiary Hearing;

(5) Develop a schedule or schedules for any anticipated motions;

(6) Schedule a date(s) for the Evidentiary Hearing, which shall be within ninety (90) days of the prehearing conference described in this subsection, unless a different date or dates is specified by the Hearing Officer or the Hearing Body and with the consent of all Participants or for good cause shown; and

(7) Address such other matters as may aid in the simplification of the evidence and disposition of the proceeding.

(b) The Hearing Officer shall also hold a final prehearing conference prior to the Evidentiary Hearing, for the purpose of discussing:

(1) the anticipated duration of the hearing;

(2) the scheduling of witnesses' appearances to testify;

(3) the issues anticipated to be presented at the hearing;

(4) whether prehearing memoranda should be filed and if so, the schedule; and

(5) any other matters identified by the Hearing Officer for the management of the Evidentiary Hearing.

Participants may submit to the Hearing Officer, at least ten (10) days prior to the scheduled date of the final prehearing conference, a proposed list or lists of matters to be discussed at the final prehearing conference.

1.5.3 Summary Disposition

(a) Availability

A Hearing Officer, on the Hearing Officer's own motion or on the motion of a Participant, may issue an initial opinion granting, in whole or in part, summary disposition if it appears that there are no issues of material fact and a Participant is entitled to issuance of a final order in its favor.

(b) Motion for Summary Disposition and Responses

(1) A Participant moving for summary disposition must clearly identify the material facts that are not in dispute, demonstrate that there are no other material facts in dispute, and demonstrate that on the basis of the undisputed material facts, the Participant is entitled to issuance of a final order in its favor.

(2) A Participant opposing a motion for summary disposition must clearly identify in its response to the motion the material facts that the Participant contends remain in dispute, and/or explain why the moving Participant is not entitled to issuance of a final order in its favor even though there are no disputed issues of material fact.

(c) Summary Disposition on the Hearing Officer's Own Motion

If the Hearing Officer is considering summary disposition in the absence of a Participant motion, the Hearing Officer shall request the Participants to identify in writing any issues of material fact and to comment on the proposed disposition. Factual information in the Participants' comments shall be supported by affidavit. Following review of the Participants' comments, if it still appears to the Hearing Officer that there are no genuine issues of material fact, the Hearing Officer may proceed without an Evidentiary Hearing. The Hearing Officer shall, however, allow the Participants the opportunity to file briefs.

(d) Hearing Officer's Initial Opinion Granting Summary Disposition

When the Hearing Officer issues an initial opinion granting summary disposition in whole or in part, the ruling shall set forth the rationale for the grant. An initial opinion of the Hearing Officer granting summary disposition shall be confirmed, rejected or modified in a final order issued by the Hearing Body.

1.5.4 Status Hearings

Any Participant may request, and the Hearing Officer may call, a status hearing at any time subsequent to the initial prehearing conference to address issues that have arisen between the Participants or other matters relevant to the conduct of the hearing. Such issues may include, but are not limited to, discovery disputes and scheduling matters. A Participant requesting a status hearing to resolve a dispute shall include in its request a certification that it has made a good faith effort to resolve the dispute with the other Participant(s) before requesting the status hearing. The Hearing Officer shall direct the Clerk to issue a notice of status hearing that sets forth the date, time and place for the hearing, and identifies the matters to be addressed at the hearing.

1.5.5 Motions and Responses

(a) Unless otherwise provided in these Hearing Procedures or by the procedural schedule established by the Hearing Officer or Hearing Body, a Participant may file a motion at any time requesting any relief as may be appropriate. Unless the Hearing Officer allows a motion to be made orally on the record, motions shall be filed in writing. Motions based on facts that do not appear of record shall be supported by affidavit.

(b) Unless otherwise specified by the Hearing Officer or Hearing Body, responses to motions shall be filed within fourteen (14) days after service of the motion, and replies to responses shall be filed within seven (7) days after service of the responses. A Hearing Officer or Hearing Body may deny dilatory, repetitive, or frivolous motions without awaiting a response. Unless otherwise ordered by a Hearing Officer or Hearing Body, the filing of a motion does not stay the proceeding or extend any scheduled dates in the proceeding.

1.5.6 Experts

(a) A Participant may employ an expert(s) to testify or consult in a proceeding. Any expert utilized in either capacity shall sign an agreement evidencing the expert's understanding and acknowledgement of the non-public nature of the proceeding and that unauthorized public disclosure of information obtained in connection with the expert's participation in the proceeding is prohibited.

(b) The Participant employing the expert shall propose the agreement for approval by a motion, and its approval shall be subject, in addition to consideration of any objections by other Participants, to ensuring that appropriate safeguards are maintained to protect the confidentiality of the proceeding and the information disclosed therein.

1.5.7 Inspection and Copying of Documents in Possession of Staff

(a) Documents to be Available for Inspection and Copying

(1) Within twenty-five (25) days after the date the request for hearing is filed, Staff shall make available for inspection and copying by the other Participants, all Documents prepared or obtained by Staff through or in connection with any compliance monitoring processes that led to the institution of proceedings. Such Documents shall include but are not limited to:

(A) requests for information to the Respondent;

(B) every written request, including e-mail, directed to persons not employed by the Compliance Enforcement Authority to provide information or Documents or to be interviewed;

(C) the Documents provided in response to any such requests described in (A) and (B) above;

(D) all transcripts of testimony recorded during the Staff investigation and all exhibits to the transcript;

(E) all other Documents obtained from the Respondent; and

(F) all other Documents obtained from persons not employed by the Compliance Enforcement Authority.

The sole grounds on which Staff is authorized to withhold Documents from inspection and copying are the bases set forth in subsection 1.5.7(b); provided, however, that the Documents made available for inspection and copying need not include (i) exact copies of Documents the Respondent previously provided to Staff, and (ii) any Documents provided to the Respondent with or as part of the Notice of Alleged Violation, Notice of Penalty, assessment of proposed Mitigation Plan or Remedial Action Directive.

(2) Where there are Participants in a proceeding in addition to a single Respondent and Compliance Staff, the Hearing Officer or Hearing Body shall oversee the Staff's designation of Documents to be produced to such other Participants and the development, execution and enforcement of any protective order deemed necessary.

(3) Staff shall promptly inform the Hearing Officer and each other Participant if, after the issuance of a notice of hearing, requests for information are issued by Staff related to the same compliance monitoring process(es) that led to the institution of the proceeding. If Staff receives Documents pursuant to a request for information after Staff has made Documents available for inspection and copying as set forth in subsection (a)(1), the additional Documents shall be made available to the Participants not later than fourteen (14) days after Staff receives such Documents. If a date for the Evidentiary Hearing has been scheduled, Staff shall make the additional Documents available to the other Participants not less than ten (10) days before the Evidentiary Hearing. If Staff receives such Documents ten or fewer days before the Evidentiary Hearing is scheduled to begin or after the Evidentiary Hearing begins, Staff shall make the additional Documents available immediately to the other Participants.

(4) Nothing in subsection (a)(1) shall limit the discretion of the Compliance Enforcement Authority to make any other Document available to the Participants or the authority of the Hearing Officer to order the production of any other Documents or information by any Participant.

(b) Documents That May Be Withheld by Staff

(1) Staff may withhold a Document from inspection and copying by a Participant if:

(A) the Document is privileged to the Compliance Enforcement Authority or constitutes attorney work product of counsel for the Compliance

Enforcement Authority (in applying this provision, the attorney-client privilege shall be recognized as absolute and any demand for production of attorney work product shall be granted only after a showing of substantial need by the Respondent or other Participant);

(B) the Document is an examination or inspection report, an internal memorandum, or other note or writing prepared by a Staff member that will not be offered in evidence or otherwise relied on by Staff in the hearing;

(C) the Document would disclose

(i) an examination, investigatory or enforcement technique or guideline not otherwise made public of the Compliance Enforcement Authority, a federal, state, or foreign regulatory authority, or a self-regulatory organization;

(ii) the identity of a source, including a federal, state, or foreign regulatory authority or a self-regulatory organization, that furnished information or was furnished information on a confidential basis regarding an investigation, an examination, an enforcement proceeding, or any other type of civil or criminal enforcement action; or

(iii) an examination, an investigation, an enforcement proceeding, or any other type of civil or criminal enforcement action under consideration by, or initiated by, the Compliance Enforcement Authority, a federal, state, or foreign regulatory authority, or a self-regulatory organization; or

(D) the Hearing Officer grants leave to withhold a Document or category of Documents as not relevant to the subject matter of the proceeding, or for other good cause shown.

Provided, that where a Document contains information of the type listed in subsections (A), (B), (C) or (D) that is capable of being redacted, Staff shall make the Document available for inspection and copying by the other Participants in redacted form.

(2) Nothing in subsections (b)(1)(B), (C) or (D) authorizes Staff to withhold a Document, or a part thereof, that contains exculpatory evidence. Nothing in subsection (b)(1) requires Staff to withhold a Document from disclosure.

(c) Withheld Document List

At the time it is required to make Documents available for inspection and copying, Staff shall also provide to the Hearing Officer, the Respondent and any other Participant to which Documents are being made available, a list of Documents withheld by Staff pursuant to

subsection (b)(1), with a statement of the grounds that support withholding the Document. Upon review, for good cause shown, the Hearing Officer may order Staff to make any Document withheld, other than a Document that is subject to the attorney-client privilege, available to the other Participants for inspection and copying.

(d) Timing of Inspection and Copying

Except as set forth in this Section, the Hearing Officer shall determine the schedule of production of Documents for inspection and copying, provided that the Hearing Officer may modify any time period for production set forth in this Section as warranted by the circumstances.

(e) Place and Time of Inspection and Copying

Documents subject to inspection and copying pursuant to this Section shall be made available to the Respondent and other Participants for inspection and copying at the Compliance Enforcement Authority office where the Documents are ordinarily maintained, or at such other office as the Hearing Officer, in his or her discretion, shall designate, or as the Participants otherwise agree. A Participant shall be given access to the Documents at the Compliance Enforcement Authority's offices during normal business hours. A Participant shall not be given custody of the Documents or be permitted to remove the Documents from the Compliance Enforcement Authority's offices, other than copies of Documents made available by the Compliance Enforcement Authority for that purpose.

(f) Copying Costs

A Participant may obtain a photocopy of all Documents made available for inspection. A Participant shall be responsible for the cost of photocopying. Unless otherwise ordered by the Hearing Officer, charges for copies made at the request of a Participant shall be at a rate to be established by the Compliance Enforcement Authority.

(g) Failure to Make Documents Available — Harmless Error

In the event that a Document required to be made available to a Participant pursuant to this Section is not made available by Staff, no rehearing or amended decision of a proceeding already heard or decided shall be required where the failure to make the Document available was harmless error. Should a dispute arise as to whether a rehearing or amended decision is required due to the failure of Staff to produce a Document, the burden shall be on Staff to show that such failure was harmless error. The Hearing Officer, or, upon review, the Hearing Body shall determine whether the failure to make the Document available was harmless error.

1.5.8 Other Discovery Procedures

(a) In addition to the production of Documents by Staff for inspection and copying by Respondent and other Participants pursuant to Section 1.5.7, the Participants shall be entitled to utilize all other discovery methods provided for in Rules 402 through 409 of the FERC Rules of Practice and Procedure, 18 C.F.R. §385.402 through 385.409, including data requests, written interrogatories and requests for production of Documents or things, depositions by oral

examination, requests for inspection of Documents and other property, requests for admissions, and requests for issuance of orders to one or more Registered Entities to produce Documents for inspection and copying or at the hearing or to provide testimony by an authorized representative in deposition or at the hearing.

(b) Unless otherwise directed by the Hearing Officer or Hearing Body upon motion by a Participant, or by the Hearing Officer, or by the Hearing Body on its own motion, such discovery, and the resolution of any disputes concerning such discovery, shall be conducted in accordance with the provisions of Rules 402 through 410 and 510(e) of the FERC Rules of Practice and Procedure, 18 C.F.R. §385.402 through 385.410 and 385.510(e), which are hereby incorporated by reference into these Hearing Procedures, subject to the following limitations and modifications to such Rules:

(1) The provisions of subsections (d), (e) and (f) of Section 1.5.7 shall apply to any such discovery.

(2) Rule 403(b)(2) (18 C.F.R. §385.403(b)(2)) and Rule 410(d)(2) (18 C.F.R. §385.410(d)(2)) shall not be applicable.

(3) The Hearing Officer and the Hearing Body have the authority to issue orders to compel the appearance by or production of Documents or information by, only a Person that (i) is a Participant or (ii) is a Registered Entity (including an authorized representative thereof) that is not a Participant. The Hearing Officer and the Hearing Body do not have authority to require a United States marshal or deputy marshal to serve an order to produce or provide Documents, information or testimony.

(4) References to "subpoena" in Rules 404, 409, 410 and 510(e) shall be deemed to be to an order to a non-Participant Registered Entity to produce or provide Documents, information or testimony.

(5) References to the "Commission" in Rules 402 through 410 and 510(e) shall be to FERC except as follows:

(i) the references in Rules 402(a), 404(b)(1) and 405(b), the second reference in Rule 410(d), and the references in Rule 510(e)(1) and (2) shall be deemed to be to the Hearing Body,

(ii) the reference in Rule 385.406(b)(4) to "Commission trial staff" shall be deemed to be to Compliance Staff, and

(iii) the reference in Rule 510(e)(3) shall be deemed to be to the Hearing Officer or Hearing Body.

(6) Unless otherwise ordered by the Hearing Officer or Hearing Body, a data request, set of interrogatories, request for production of Documents or things, request for inspection of Documents or other property, request for admissions, or order to

produce or provide Documents, information or testimony, shall not specify a due date or response date that is fewer than 21 days from the date of service of the request or date of the order.

(7) A list of withheld Documents, if any, shall be provided by any Participant required to produce Documents, at the time the Documents are required to be produced, to the Hearing Officer and to each Participant entitled to receive production of the Documents. Upon review, for good cause shown, the Hearing Officer may order the Participant to make any Document withheld available to any other Participant or Participants for inspection and copying.

(8) In the event a Document or information required to be produced or provided by a Participant pursuant to discovery is not produced or provided by the Participant, no rehearing or amended decision of a proceeding already heard or decided shall be required where the failure to produce or provide the Document or information was harmless error. Should a dispute arise as to whether a rehearing or amended decision is required due to the failure of a Participant to produce or provide a Document or information, the burden shall be on the Participant that failed to produce or provide the Document or information to show that such failure was harmless error. The Hearing Officer or, upon review, the Hearing Body shall determine whether the failure to make the Document available was harmless error.

(9) Unless otherwise ordered by the Hearing Officer or Hearing Body, all such discovery shall be requested, scheduled and conducted so as to be completed within six (6) months following the date the request for hearing was filed.

(10) Notwithstanding subsections (b)(6) and (b)(9), however, if the shortened hearing procedure in Section 1.3.4 is used in a proceeding, the Hearing Officer, on his or her own motion or on motion of a Participant, shall establish a schedule for discovery, including response periods for responding to discovery requests, that are consistent with the expedited nature of the proceeding contemplated by the shortened hearing procedure.

(c) The Hearing Officer's ruling on all motions relating to disputes concerning such discovery shall consider the following objectives:

(1) full disclosure of all relevant Documents and information;

(2) the exercise of due diligence in the conduct of discovery by a Participant; and

(3) disallowing use of discovery as a means to delay the proceeding or to harass or burden any other Participant.

1.5.9 Pre-Evidentiary Hearing Submission of Testimony and Evidence

(a) Unless the Hearing Officer orders otherwise and with the exception of (i) any adverse Participant examination pursuant to Section 1.6.16 and (ii) the testimony and Documents of a non-Participant provided pursuant to an order to produce or provide Documents, information or testimony, all witness direct testimony to be submitted in an Evidentiary Hearing must be prepared in written form, may have exhibits, schedules and attachments thereto, and shall be filed in advance of the Evidentiary Hearing pursuant to a schedule determined by the Hearing Officer, as it may be amended.

(b) Where a Participant intends to use a Document or other demonstrative evidence that has not been filed as part of written testimony in the conduct of cross-examination (other than Documents that are to be produced by a non-Participant at the hearing pursuant to an order to produce Documents), the Participant intending to use such Document or demonstrative evidence shall provide it to the other Participants and the Hearing Officer at least three (3) business days prior to the date at which the witness will be cross-examined at a Testimonial Hearing.

(c) Compliance Staff shall file the Documents it intends to offer into evidence as its direct case, including the written testimony of its witnesses along with exhibits, schedules and attachments thereto, first. The Registered Entity shall file the Documents it intends to offer into evidence as its direct case, which also may be responsive to Staff's direct case, including the written testimony of its witnesses along with exhibits, schedules and attachments thereto, second. Staff shall file as its rebuttal case the Documents it intends to offer into evidence in response to the Registered Entity's direct case, including the written testimony of its witnesses along with exhibits, schedules and attachments thereto, third.

(d) If appropriate due to the number and/or complexity of the issues, the Hearing Officer may allow for the Registered Entity to submit a rebuttal case that responds to Staff's rebuttal case, in which event the Hearing Officer shall also allow Staff to submit a surrebuttal case that responds to the Registered Entity's rebuttal case.

(e) Each round of evidence shall be limited in scope to responding to the preceding round of evidence, except that the Registered Entity's direct case may exceed the scope of Staff's direct case if necessary for the Registered Entity to set forth its direct case fully.

(f) The Participants shall file the Documents they intend to offer into evidence in accordance with the Hearing Officer's schedule, as it may be amended. Such filings of written testimony and other evidence in advance of the Evidentiary Hearing shall not entitle the Documents to be admitted into the evidentiary record. The Participants must offer their witnesses' testimony and other proposed evidence for admission into the evidentiary record during the Evidentiary Hearing.

(g) Any Participant who fails, without good cause shown, to comply with the Hearing Officer's schedule for the filing of written testimony and other evidence in advance of the Evidentiary Hearing may be limited in the presentation of its evidence during the Evidentiary Hearing or have its participation in the Evidentiary Hearing otherwise restricted by the Hearing Officer to avoid undue prejudice and delay.

1.5.10 Protective Orders

(a) All proceedings conducted pursuant to these Hearing Procedures, and any written testimony, exhibits, other evidence, transcripts, comments, briefs, rulings and other issuances, shall be non-public and shall be held in confidence by all Participants, except as the ERO (within the U.S., in accordance with the authorization previously granted by FERC to release information about a non-public proceeding) or FERC (in the case of U.S.-related information) or another Applicable Governmental Authority (in the case of non-U.S.-related information) authorizes or directs public disclosure of any portion of the record. In addition to this general proscription, at any time during a proceeding, the Hearing Officer, on his or her own motion or on the motion of any Participant or of any non-Participant ordered to produce Documents, information or testimony, may enter a protective order to designate as proprietary and protect the confidential, proprietary or trade secret nature of any data, information or studies, or any other information the public release of which may cause a security risk or harm to a Participant.

(b) The following types of information will be considered entitled to protection through a protective order:

(1) Confidential Business and Market Information, including information that is proprietary, commercially valuable, or competitively sensitive;

(ii) Critical Energy Infrastructure Information;

(iii) information related to a Cyber Security Incident;

(iv) personnel information that identifies or could be used to identify a specific individual, or that reveals personnel, financial, medical or other personal information;

(v) audit work papers;

(vi) investigative files or Documents that would disclose investigative techniques of Staff, any Compliance Enforcement Authority, the ERO or any federal, state or foreign regulatory authority.

Nothing in this subsection 1.5.10(b) shall require Staff to produce any Documents it is entitled to withhold under subsection 1.5.7(b).

(c) A motion for a protective order shall specify the proposed expiration date for the proprietary status of the data, Documents or information, if any, and shall propose requirements or safeguards to be met for individuals participating in the proceeding to review the protected information while maintaining its proprietary status.

(d) A Document submitted and marked as proprietary, or a statement made at a hearing and identified as proprietary, shall be afforded proprietary treatment pending the timely submission of a motion to protect the confidential, proprietary or trade secret nature of that Document or statement and a ruling on such a motion by the Hearing Officer.

(e) The protective order shall identify the data, Documents or information that will be accorded proprietary treatment; the individuals participating in the proceeding, by category or otherwise, entitled to view the proprietary information; and the requirements, conditions or safeguards that must be met before an individual may view the information.

(f) A public redacted version of each Document and transcript that contains information that is protected pursuant to this Section must be filed with the proprietary version and must be served on each Participant for distribution to those individuals participating in the proceeding who are not entitled to view the proprietary information.

(g) Should it be necessary to address proprietary information during a hearing, the Hearing Officer shall, while the information is being addressed, close the hearing to all individuals other than those entitled to view or hear the proprietary information in accordance with the protective order.

1.5.11 Pre-Evidentiary Hearing Memorandum

(a) The Hearing Officer or the Hearing Body may request the submission of memoranda prior to the Evidentiary Hearing that set forth each Participant's position on the issue(s) in dispute, the key facts and arguments, the applicable Reliability Standard, rules, orders or other authority, and such other matters as may be directed by the Hearing Officer or the Hearing Body.

(b) The purpose of such memoranda will be to aid the Hearing Officer and Hearing Body in preparation for the Evidentiary Hearing. A Participant will not be deemed to have waived any issue, fact or argument that is not set forth in a pre-Evidentiary Hearing memorandum.

(c) The Hearing Officer may establish word limitations on such submissions.

1.5.12 Certification of Questions to the NERC Board of Trustees

(a) Should a hearing present a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the proceeding in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the NERC Board of Trustees appropriate, the Hearing Officer, on his or her own motion or on motion of a Participant, may recommend to the Hearing Body that it certify, or the Hearing Body on its own motion may decide to certify, the question to the Board of Trustees for determination pursuant to Section 412 of the Rules of Procedure.

(b) If the Hearing Officer, on his or her own motion, or the Hearing Body, on its own motion, wishes to present a question to the Hearing Body for certification to the NERC Board of Trustees, the Hearing Officer shall first provide the Participants the opportunity to submit memoranda addressing whether the question should be certified and the precise terms of the question to be certified.

(c) If a Participant files a motion requesting, or the Hearing Officer determines on his or her own motion, that a question should be certified to the Board of Trustees, the Hearing Officer shall submit a written recommendation on the matter to the Hearing Body. If the request for certification is based on the motion of a Participant, the Hearing Officer shall also submit to the Hearing Body the motion and any answers to the motion that were filed. If the request for

certification is on the Hearing Officer's own motion, the Hearing Officer shall also submit to the Hearing Body the Participants' memoranda that were filed pursuant to subsection (b).

(d) Questions of fact presented by the particular matter in dispute in a hearing shall not be the subject of a certification to the Board of Trustees.

(e) The Hearing Body shall determine, based on the criteria specified in subsection (a), whether the proposed question shall be certified to the Board of Trustees for determination. To certify the proposed question, the Hearing Body must determine that the question is a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the proceeding, in whole or in part, and that there are extraordinary circumstances that make prompt consideration of the question by the Board of Trustees appropriate. If the Hearing Body determines that the proposed question should be certified to the Board of Trustees, the Hearing Body shall also determine whether the hearing should be suspended, in whole or in part, while the question is pending before the Board of Trustees for determination.

(f) As provided in Rule of Procedure Section 412, the Board of Trustees may decide to reject a proposed certification from a Hearing Body.

(f) If the Board of Trustees accepts certification of a question and issues a determination on the question, the hearing shall proceed following the determination in accordance with the Board of Trustees' decision.

1.6 Procedure at Evidentiary Hearing

1.6.1 Purpose of Evidentiary Hearing

The purpose of the Evidentiary Hearing shall be to admit the Participants' evidence into the record, and for each Participant to have the opportunity to cross-examine the other Participant's witnesses. A schedule for briefs, unless waived by the Participants, shall be set at the conclusion of the Evidentiary Hearing.

1.6.2 Order of Receiving Evidence

In all proceedings Compliance Staff shall open and close.

1.6.3 Opening and Closing Statements

Opening and closing statements will not be made during the Evidentiary Hearing as a matter of course except that such statements may be allowed when requested by a Participant, and shall be required when requested by the Hearing Officer or the Hearing Body. Any Participant's request for such statements, or a Hearing Officer or Hearing Body notice requiring such statements, shall be made at least ten (10) days in advance of the start of the Evidentiary Hearing.

1.6.4 Right of Participant to Present Evidence

Subject to compliance with the requirements of these Hearing Procedures concerning the timing of submission of written testimony and other evidence, a Participant has the right to present such

evidence, to make such objections and arguments, and to conduct such cross-examination as may be necessary to assure the true and full disclosure of the facts.

1.6.5 Exhibits

(a) All material offered in evidence, except oral testimony allowed by the Hearing Officer or the testimony of a non-Participant pursuant to an order to produce or provide Documents, information or testimony, shall be offered in the form of an exhibit.

(B) Each exhibit must be marked for identification. A Participant must provide the court reporter with two (2) copies of every exhibit that the Participant offers into evidence, and will provide copies of any exhibit not served in advance of the Evidentiary Hearing to the Participants and the Hearing Officer.

1.6.6 Witness Attendance at Testimonial Hearing

(a) Each witness shall attend the Testimonial Hearing in person unless a Participant has been informed in advance of the Testimonial Hearing that all other Participants waive cross-examination of the witness and neither the Hearing Officer nor the members of the Hearing Body have any questions for the witness, in which event the witness does need not be present at the Testimonial Hearing.

(b) A person compelled to appear, voluntarily testifying, or making a statement may be accompanied, represented and advised by an attorney.

(c) All testimony offered at a Testimonial Hearing is to be under oath or affirmation. If a witness is not required to attend the Testimonial Hearing, then the Participant on whose behalf the witness prepared testimony shall submit an affidavit of the witness attesting to the veracity of the witness' testimony, and the Participant shall be allowed to introduce the witness' testimony, and the exhibits, schedules and attachments thereto, into the evidentiary record based on such affidavit.

1.6.7 Admission of Evidence

(a) Compliance Staff shall offer its exhibits into evidence first and the Registered Entity second, unless the Participants agree otherwise.

(b) Except for witnesses who are not required to attend the Testimonial Hearing, the Participants shall call each witness in turn. Following the witness' swearing in, the witness shall attest to the veracity of his or her written testimony. The witness may identify any language and/or figures in his or her written testimony or exhibits that the witness would like to change or correct. Subject to objection, such changes or corrections may be allowed at the Hearing Officer's discretion for the purpose of obtaining a full, accurate and complete record without imposing undue delay or prejudice on any Participant. The Participant whose witness has made changes or written corrections to written testimony and exhibits shall file corrected copies with the Clerk and provide corrected copies to the Hearing Officer and other Participant.

(c) Once a witness has attested to the veracity of his or her testimony, the Participant on whose behalf the witness is testifying shall move for admission of the witness' testimony,

including all exhibits, schedules and attachments thereto, into evidence. Other Participants may object to the introduction of the witness' testimony, or any part thereof, as set forth in Section 1.6.11. Subject to the Hearing Officer's ruling on the objection, the witness' testimony shall be admitted into evidence.

(d) The witness shall then be turned over for cross-examination by other Participants, and for any questions by the Hearing Officer or any member of the Hearing Body, in accordance with Section 1.6.14, and then for redirect examination in accordance with Section 1.6.15. Witnesses shall be cross-examined on all previously-served testimony (direct, rebuttal or surrebuttal) when they first take the witness stand.

(e) Except (i) in exceptional cases and upon a showing of good cause and (ii) witnesses testifying pursuant to an order to produce or provide Documents, information or testimony issued to a non-Participant, no witness shall be allowed to testify unless a Participant has served the witness' written testimony in advance of the Testimonial Hearing in accordance with the schedule established by the Hearing Officer. Due to the undue prejudice such surprise witness testimony would impose on other Participants, it is the Compliance Enforcement Authority's policy to discourage witness testimony at a Testimonial Hearing when a Participant has not served the witness' written testimony in advance of the Testimonial Hearing. If such testimony is allowed, sufficient procedural steps shall be taken by the Hearing Officer to provide the other Participants with a fair opportunity for response and cross-examination.

1.6.8 Evidence that is Part of a Book, Paper or Document

(a) When relevant and material matter offered in evidence is embraced in a book, paper or Document containing other matter that is not material or relevant, the Participant offering the same must plainly designate the matter offered as evidence, and segregate and exclude the material not offered to the extent practicable.

(b) If the material not offered is in such volume as would unnecessarily encumber the record, such book, papers or Document will not be received in evidence but may be marked for identification and, if properly authenticated, the relevant or material matter may be read into the record, or, if the Hearing Officer so directs, a separate copy of such matter in proper form shall be offered as an exhibit.

(c) All other Participants shall be afforded an opportunity to examine the book, paper or Document and to offer in evidence in like manner other portions thereof if found to be material and relevant.

1.6.9 Stipulations

The Participants may stipulate to any relevant fact or the authenticity of any relevant Document. Stipulations may be made in writing or entered orally in the record. Notwithstanding stipulation, the Hearing Officer may require evidence of the facts stipulated in order to provide a complete evidentiary record on which to base the final order.

1.6.10 Official Notice

(a) Where relevant and material to the subject matter of the proceeding, the Hearing Officer may, upon request of a Participant, take official notice of any of the following:

(1) Rules, regulations, administrative rulings and orders, written policies of governmental bodies, and rulings and orders of other Compliance Enforcement Authorities.

(2) The orders, transcripts, exhibits, pleadings or any other matter contained in the record of other docketed proceedings of the Compliance Enforcement Authority.

(3) State, provincial and federal statutes and municipal and local ordinances.

(4) The decisions of state, provincial and federal courts.

(5) Generally recognized scientific or technical facts within the specialized knowledge of the Compliance Enforcement Authority.

(6) All other matters of which the courts of the United States may take judicial notice.

(b) All requests to take official notice shall be submitted in advance of the Evidentiary Hearing in accordance with a schedule established by the Hearing Officer. Before ruling on a request to take official notice, the Hearing Officer shall afford the other Participant opportunity to object or to show the contrary to the matter for which official notice is requested.

(c) An accurate copy of any item officially noticed shall be introduced into the record in the form of an exhibit presented by the Participant requesting official notice unless waived by the Participants and approved by the Hearing Officer. Any information officially noticed and not presented as an exhibit shall be set forth in a statement on the record.

1.6.11 Admissibility of Evidence

(a) Any evidence offered, including that included in a book, paper or Document pursuant to Section 1.6.8, shall be subject to appropriate and timely objections. Any Participant objecting to the admission or exclusion of evidence must state the grounds for objection.

(b) The admission of evidence shall not be limited by the generally recognized rules of evidence as applied in the courts of the United States or of the states, although the Hearing Officer may take such rules of evidence into consideration in ruling on the admissibility of evidence. The Hearing Officer will exercise discretion in the admission of evidence based upon arguments advanced by the Participants, and shall admit evidence if it is of a type commonly relied upon by reasonably prudent persons in the conduct of their affairs. The Hearing Officer may only exclude material from the record in response to a motion or objection by a Participant.

(c) Formal exception to a ruling on admissibility of evidence need not be taken to be preserved.

1.6.12 Offer of Proof

Any Participant who has had evidence excluded may make an offer of proof on the record. The offer of proof may consist of a statement made on the record of the substance of the evidence that the Participant claims would have been adduced, or any written or documentary exhibit that the Participant sought to introduce. Any such exhibit shall be retained as part of the record.

1.6.13 Reservation of Evidentiary Ruling

(a) The Hearing Officer shall rule upon any objection to the admissibility of evidence at the time the objection is made; provided that the Hearing Officer has discretion to reserve such a ruling or to require the Participants to file written arguments in relation thereto.

(b) If the Hearing Officer reserves the ruling, appropriate steps shall be taken during the Evidentiary Hearing to ensure a full, complete and accurate record in relation to the objected to evidence in the event the objection to the evidence's admissibility is overruled.

1.6.14 Cross-Examination

(a) Each witness shall be tendered for cross-examination subsequent to the admission of the witness' testimony into the evidentiary record. Each Participant shall have the right to cross-examine each witness of any other Participants. A Participant may waive cross-examination of any witness. Leading questions are permitted on cross-examination.

(b) The credibility of a witness may be attacked by any Participant, including the Participant calling the witness.

(c) The Hearing Officer and any member of the Hearing Body may ask the witness questions following the conclusion of the witness' cross-examination by the other Participant, and prior to the witness' redirect examination pursuant to Section 1.6.15.

1.6.15 Redirect Examination

A Participant shall be entitled to conduct redirect examination of each of the Participant's witnesses who are subject to cross-examination or questions of the Hearing Officer or a member of the Hearing Body. Any redirect examination shall be limited in scope to the witness' cross-examination and questions of the Hearing Officer and members of the Hearing Body.

1.6.16 Examination of Adverse Participant

(a) Any Participant may call any adverse Participant, or any employee or agent thereof, during the Testimonial Hearing to provide oral testimony on the Participant's behalf, and may conduct such oral examination as though the witness were under cross-examination.

(b) If a Participant intends to call an adverse Participant for examination, it shall give notice to the Hearing Officer and all other Participants setting forth the grounds for such examination at least fourteen (14) days in advance of the Testimonial Hearing, and the Participant who, or whose employee or agent, is sought to be called shall file any objection at least seven (7) days in advance of the Testimonial Hearing.

(c) Any Participant may conduct oral examination of a witness testifying pursuant to an order to produce or provide Documents, information or testimony issued to a non-Participant, as though the witness were under cross-examination.

1.6.17 Close of the Evidentiary Record

(a) The Hearing Officer shall designate the time at which the evidentiary record will be closed, which will typically be at the conclusion of the Evidentiary Hearing.

(b) Evidence may not be added to the evidentiary record after it is closed, provided that, prior to issuance of the Hearing Body's final order, the Hearing Officer may reopen the evidentiary record for good cause shown by any Participant. For the purpose of reopening the evidentiary record, newly discovered evidence that is material to the issues in dispute and could not, by due diligence, have been discovered prior to or during the Evidentiary Hearing, shall constitute good cause.

1.7 Post- Evidentiary Hearing Procedure

1.7.1 Briefs

(a) At the close of the Evidentiary Hearing, Participants may file initial and reply briefs.

(b) Briefs shall be concise, and, if in excess of twenty (20) pages, excluding appendices, shall contain a table of contents. Statements of fact should be supported by record citations.

(c) The Hearing Officer will prescribe the time for filing briefs, giving due regard to the nature of the proceeding, the extent of the record, the number and complexity of the issues, and the objective of expedition.

(d) Unless the Hearing Officer prescribes otherwise, all Participants shall file initial and reply briefs simultaneously.

(e) Participants' reply briefs shall be limited in scope to responding to arguments and issues raised in other Participants' initial briefs.

(f) The Hearing Officer may allow oral closing statements to be made on the record in lieu of briefs.

(g) The Hearing Officer may establish reasonable word limitations applicable to briefs.

1.7.2 Other Pleadings

Post-hearing pleadings other than briefs are permitted, but, absent good cause shown, such pleadings may not seek to introduce additional evidence into the record.

1.7.3 Draft Initial Opinions

The Hearing Officer may permit or require Participants to file draft initial opinions that set forth the Participants' proposed findings of fact and conclusions.

1.7.4 Hearing Officer's Initial Opinion

(a) At the conclusion of the Evidentiary Hearing, and following the submission of initial and reply briefs and draft orders, if any, the Hearing Officer shall prepare an initial opinion for the Hearing Body's review and consideration.

(b) The initial opinion shall include a statement of each finding and conclusion, and the reasons or basis therefore, for all material issues presented on the record. The initial opinion also shall contain the appropriate orders to dispose of the proceeding, including any Penalty, Mitigation Plan or Remedial Action Directive that the Hearing Officer proposes the Hearing Body require.

(c) The initial opinion shall note if the subject of the proceeding has been deemed to involve a Cyber Security Incident, if any information in the proceeding was deemed to be Critical Energy Infrastructure Information, or if any information in the proceeding is the subject of a protective order pursuant to Section 1.5.10.

1.7.5 Exceptions

(a) Within twenty-one (21) days after service of the initial opinion, or such other time as is fixed by the Hearing Officer, any Participant may file exceptions to the initial opinion in a brief designated "brief on exceptions" and, within fourteen (14) days after the time for filing briefs on exceptions or such other time as is set by the Hearing Officer, any Participant may file as a reply, a "brief in reply to exceptions."

(b) Exceptions and replies thereto with respect to statements, findings of fact or conclusion in the initial opinion must be specific and must be stated and numbered separately in the brief. With regard to each exception, the Participant must specify each error asserted, and include a concise discussion of any policy considerations applicable and any other evidence and arguments in support of the Participant's position. Suggested replacement language for all statements to which exception is taken must be provided. Exceptions and arguments may be filed (1) together in one brief; or (2) in two separate documents, one designated as the brief containing arguments, and the other designated "Exceptions," containing the suggested replacement language.

(c) Arguments in briefs on exceptions and replies thereto shall be concise and, if in excess of twenty (20) pages, shall contain a table of contents.

(d) Participants shall not raise arguments in their briefs in reply to exceptions that are not responsive to any argument raised in any other Participant's brief on exceptions.

(e) Statements of fact should be supported by citation to the record.

(f) The Hearing Officer may establish reasonable word limitations applicable to arguments included in briefs on exception and briefs in reply to exceptions. Such word limitations shall not apply to a Participant's proposed replacement language.

(g) Unless good cause is shown, if a Participant does not file a brief on exceptions, or if a Participant filed a brief on exceptions that does not object to a part of the initial opinion,

the Participant shall be deemed to have waived any objection to the initial opinion in its entirety, or to the part of the initial opinion to which the Participant did not object, whichever applies. This provision shall not prohibit the Participant, in its brief in reply to exceptions, from responding to another Participant's exceptions to such part of the initial opinion or from proposing alternative replacement language to the replacement language proposed by the other Participant for such part of the initial opinion.

1.7.6 Oral Argument

(a) The Hearing Body may elect to hear oral argument. If oral argument is held without briefs having been filed, Participants will be given the opportunity to present argument on all issues.

(b) If oral argument is held where briefs have been filed, argument may be limited to issues identified by the Hearing Body. The Hearing Body will direct the Clerk to issue a notice of oral argument that identifies the date, time, place and issues for the argument.

(c) The presentation of written materials or visual aids is permitted at oral argument. To the extent such materials or aids contain factual information, they shall be supported by the record, and contain accurate citations to the record. Such materials or aids may not contain new calculations or quantitative analyses not presented in the record, unless they are based on underlying data contained in the record. Copies of all written materials or visual aids to be presented at oral argument shall be served on all Participants not less than forty-eight (48) hours prior to the time and date of oral argument.

1.7.7 Additional Hearings

After the evidentiary record has been closed but before issuance of the Hearing Body's final order, the Hearing Officer may reopen the evidentiary record and hold additional hearings. Such action may be taken on the Hearing Officer's or the Hearing Body's own motion if there is reason to believe that reopening is warranted by any changes in conditions, or by the need to compile a complete evidentiary record on which to base the final order. Any Participant may file a motion to reopen the record, which shall contain the reasons for reopening, including material changes in conditions or the identification of additional evidence that should be included in the record, and a brief statement of proposed additional evidence and an explanation why such evidence was not previously adduced.

1.7.8 Hearing Body Final Order

(a) Following the receipt of the initial opinion, any exceptions and replies thereto, and oral argument, if any, the Hearing Body shall issue its final order.

(b) Issuance of a final order shall require (i) a quorum of the Hearing Body, which shall be (after any recusals, disqualifications and appointments of replacement members) at least fifty (50) percent of the number of members normally assigned to the Hearing Body, and (ii) majority vote of the members of the Hearing Body voting on the final order (which number of members voting shall not be less than a quorum).

(c) The Hearing Body shall strive, but shall not be required, to issue its final order within thirty (30) days following the last to occur of the initial opinion, exceptions or replies thereto, or oral argument. The final order may adopt, modify, amend or reject the initial opinion in its entirety or in part. The final order shall include a statement of each finding and conclusion, and the reasons or basis therefore, for all material issues presented on the record.

(d) The Hearing Body will base its determinations in the final order on the record. The final order also shall contain the appropriate orders to dispose of the proceeding, including any Penalty, Remedial Action Directive or Mitigation Plan required.

(e) The final order shall note if the subject of the proceeding has been deemed to involve a Cyber security Incident, if any information in the proceeding was deemed to be Critical Energy Infrastructure Information, or if any information in the proceeding is the subject of a protective order issued pursuant to Section 1.5.10.

(f) The service of the final order shall include a notice informing the Participants of their appeal rights to the ERO or to FERC, as applicable.

1.7.9 The Record

The Clerk shall maintain the record for all dockets. The record shall include any of the following, including all attachments thereto and Documents filed therewith, that exist in any docket:

(1) Notice of Alleged Violation and Registered Entity's response thereto;

(2) Registered Entity's proposed Mitigation Plan and Staff's statement identifying its disagreement(s) therewith;

(3) Remedial Action Directives and the Registered Entity's notice contesting the Remedial Action Directive;

(4) Registered Entity's request for a hearing;

(5) Participant filings, motions, and responses;

(6) Notices, rulings, orders and other issuances of the Hearing Officer and Hearing Body;

(7) Transcripts;

(8) Evidence received;

(9) Written comments submitted in lieu of written testimony;

(10) Matters officially noticed;

(11) Offers of proof, objections and rulings thereon, and any written or documentary evidence excluded from the evidentiary record;

(12) Pre-Evidentiary Hearing memorandums, briefs, and draft opinions;

(13) Post-hearing pleadings other than briefs;

(14) The Hearing Officer's initial opinion;

(15) Exceptions to the Hearing Officer's initial opinion, and any replies thereto;

(16) The Hearing Body's final order and the Clerk's notice transmitting the final order to the Participants;

(17) All notices of ex parte communications; and

(18) Any notifications of recusal and motions for disqualification of a member of the Hearing Body or Hearing Officer or Technical Advisor and any responses or replies thereto.

1.7.10 Appeal

A Participant or a Regional Entity acting as the Compliance Enforcement Authority, may appeal a final order of the Hearing Body to NERC in accordance with Rule of Procedure Section 409.

1.8 Settlement

Settlements may be entered into at any time pursuant to Section 5.6 of the NERC Compliance Monitoring and Enforcement Program and the Compliance Enforcement Authority's settlement procedures, provided, that (i) the Compliance Enforcement Authority may decline to engage in or continue settlement negotiations after a Possible Violation or Alleged Violation becomes a Confirmed Violation, and (ii) the Compliance Enforcement Authority, the Registered Entity or any other Participant may terminate settlement negotiations at any time.

1.9 Remedial Action Directives

1.9.1 Initiation of Remedial Action Directive Hearing

(a) Staff may issue a Remedial Action Directive to a Registered Entity at any time, including during any proceeding related to an Alleged Violation of a Reliability Standard. The Remedial Action Directive shall be delivered to the Registered Entity in accordance with Section 7.0 of the NERC Compliance Monitoring and Enforcement Program. The Compliance Enforcement Authority will notify NERC within two (2) business days after its Staff issues a Remedial Action Directive.

(b) The Registered Entity may contest the Remedial Action Directive by filing a written notice with the Clerk of the Compliance Enforcement Authority that states that the Registered Entity contests the Remedial Action Directive and that the Registered Entity requests a Remedial Action Directive hearing. The Registered Entity shall attach a copy of the Remedial Action Directive to its written notice. The Registered Entity must provide such notice within two (2) business days following the date of actual receipt (as defined in Section 7.0 of the NERC Compliance Monitoring and Enforcement Program) of the Remedial Action Directive. If the

Registered Entity does not give written notice to the Compliance Enforcement Authority within the required time period, the Registered Entity shall be deemed to have waived its right to contest the Remedial Action Directive.

(c) The Clerk shall assign a docket number, and issue a notice of hearing that sets forth the date, time and place at which the hearing will convene.

1.9.2 Remedial Action Directive Hearing Procedure

(a) Hearings to address Remedial Action Directives shall be conducted only under the expedited hearing process set forth in this Section 1.9.2. The general hearing procedures described in Sections 1.4 to 1.7 are applicable to the Remedial Action Directive hearing unless the context of a provision is inconsistent with or otherwise renders it inapplicable to the procedures set forth in this Section.

(b) The Remedial Action Directive hearing shall be presided over by a Hearing Officer and will be conducted according to the following guidelines:

(1) The Hearing Officer or the Hearing Body will hold a prehearing conference within two (2) business days after receipt of the Registered Entity's request for a hearing.

(2) A Testimonial Hearing will be conducted on the matter, in person or by teleconference, within seven (7) business days after the prehearing conference.

(3) At the Testimonial Hearing, Staff shall present oral witness testimony and evidence to show why the Remedial Action Directive should be complied with, and the Registered Entity shall present oral witness testimony and evidence to show why the Remedial Action Directive is not necessary or should be modified. All witness testimony shall be rendered under oath.

(4) At the Testimonial Hearing, the Participants shall have the opportunity to make opening statements. In addition, the Participants shall have the opportunity to make closing arguments, and Staff shall have the opportunity to make a rebuttal to the Registered Entity's closing argument.

(5) The Participants may file initial briefs and reply briefs, and/or draft opinions, on an expedited schedule set by the Hearing Officer or the Hearing Body. Oral argument shall not be held.

(c) The Hearing Body shall issue a summary written decision within ten (10) days following submission of the last brief, stating whether the Registered Entity shall or shall not be required to comply with the Remedial Action Directive and identifying any modifications to the Remedial Action Directive that the Hearing Body finds appropriate. Upon issuance of the summary written decision, the Registered Entity is required to comply with the Remedial Action Directive as specified in the summary written decision.

(d) Within thirty (30) days following issuance of its summary written decision, the Hearing Body shall issue a full written decision. The written decision shall state the conclusions of the

Hearing Body with respect to the Remedial Action Directive, and shall explain the reasons for the Hearing Body's conclusions.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: ~~March 19, 2015~~DATE

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SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted. Such functional classes[1] include: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, market operators, Planning Authorities, Transmission Planners, Resource Planners, ~~Load-Serving Entities,~~ and Distribution Providers. Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

   2.1 **Reliability Planning and Operating Performance**— Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

   2.2 **Frequency and Voltage Performance**— The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** —Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome**— Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations**— Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments or revisions to the *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

    3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

    3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment or apply to change Segments at any time.

    3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments at least every three years to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to

belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC shall assign a standards process manager to administer the development of continent-wide Reliability Standards and a regional standards manager to administer the development of Regional Reliability Standards. The standards process manager shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual*. The standards process manager and the regional standards manager shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. The regional standards manager shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC or directs NERC to develop a Reliability Standard, NERC shall within five (5) business days notify all other Applicable Governmental Authorities, and shall within thirty (30) calendar days report to all Applicable Governmental Authorities

a plan and timetable for modification or development of the Reliability Standard. Reliability Standards that are remanded or directed by an Applicable Governmental Authority shall be modified or developed using the *Standard Processes Manual*. NERC shall, during the development of a modification for the remanded Reliability Standard or directed Reliability Standard, consult with other Applicable Governmental Authorities to coordinate any impacts of the proposed Reliability Standards in those other jurisdictions. The expedited standards development process may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authorities, respecting to the extent possible the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the expedited action process described in the *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

   3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

      3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

      3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material

interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard, due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

    3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

    3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability

Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory

within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or regional Variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — NERC shall maintain a current catalog of Regional Criteria. Regional Entities shall provide a catalog listing of Regional Criteria to NERC and shall notify NERC of changes to the listing. Regional Entities shall provide any listed document to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the

governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Accreditation

NERC shall seek and maintain accreditation of the NERC Reliability Standards development process by the American National Standards Institute.

317. Five-Year Review of Reliability Standards

NERC shall complete a review of each NERC Reliability Standard at least once every five years, or such longer period as is permitted by the American National Standards Institute, from the effective date of the Reliability Standard or the latest revision to the Reliability Standard, whichever is later. The review process shall be conducted in accordance with the NERC *Standard Processes Manual*. The standards process manager shall be responsible for administration of the five-year review of Reliability Standards. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely

as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC standards information manager of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the *Standard Processes Manual*, **Appendix 3A** to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities. If the Board of Trustees is presented with a proposed Reliability Standard that fails to address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a

timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; and (iii) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

   2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

   2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

   4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in

the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

5.5 A Reliability Standard approved under paragraph 5 of this Rule shall not be eligible for submission as an American National Standard.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

SECTION 400 — COMPLIANCE ENFORCEMENT

401. Scope of the NERC Compliance Monitoring and Enforcement Program

1. **Components of the NERC Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a NERC Compliance Monitoring and Enforcement Program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC that has been approved by the Applicable Governmental Authority) has been given enforcement authority. There are four distinct parts of the NERC Compliance Monitoring and Enforcement Program: (1) NERC's oversight of the Regional Entity Compliance Monitoring and Enforcement Programs (Section 402), (2) the definition of the required Regional Entity Compliance Monitoring and Enforcement Program attributes (Section 403), (3) NERC's monitoring of Regional Entity compliance with Reliability Standards (Section 404), and (4) the monitoring of compliance with Reliability Standards that are applicable to NERC (Sections 405–406).

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users, Regional Entities, and NERC, are required to comply with all approved NERC Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered NERC Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards and compliance reporting procedures.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer a Regional Entity Compliance Monitoring and Enforcement program to meet the NERC Compliance Monitoring and Enforcement Program goals and the requirements in this Section 400.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity in the event that NERC does not have a delegation agreement, or the Regional Entity withdraws from the agreement or does not operate its Compliance Monitoring and Enforcement Program in accordance with the delegation agreement or other applicable requirements.

5.1 Should NERC not have a delegation agreement with a Regional Entity covering a geographic area, or a Regional Entity withdraws from an existing delegation agreement or the delegation agreement is otherwise terminated, NERC will directly administer the Compliance Monitoring and Enforcement Program applicable to owners, operators and users of the Bulk Power System within that geographic area.

1. This monitoring and enforcement will be accomplished by NERC and Compliance Staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant compliance information regarding Registered Entities, contacts, prior compliance information and actions, Mitigation Plans, and Remedial Action Directives for the period in which the Regional Entity was responsible for administering the Compliance Monitoring and Enforcement Program.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies collected to offset the expenses of administering the Compliance Monitoring and Enforcement Program for the geographic area.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the Compliance Monitoring and Enforcement Program within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Actively Monitored Requirements** — NERC, with input from the Regional entities, stakeholders, and regulators, shall annually select a subset of the NERC Reliability Standards and Requirements to be actively monitored and audited in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all NERC Reliability Standards whether or not they are included in the subset of Reliability Standards and Requirements designated to be actively monitored and audited in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which is incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one

Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC shall maintain a record of each compliance submission, including Self-Reported, Possible, Alleged, and Confirmed Violations of approved Reliability Standards; associated Penalties, sanctions, Remedial Action Directives and settlements; and the status of mitigation actions.

10. **Confidential Information** — NERC will treat all Possible and Alleged Violations of Reliability Standards and matters related to a Compliance Monitoring and Enforcement Program process, including the status of any Compliance Investigation or other Compliance Monitoring and Enforcement Program process, as confidential in accordance with Section 1500.

    The types of information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500. Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident, will be identified and protected from public disclosure as Critical Energy Infrastructure Information in accordance with Section 1500.

    The Regional Entity and NERC shall give Bulk Power System owners, operators, and users a reasonable opportunity to demonstrate that information concerning a violation is confidential before such report is disclosed to the public.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with a Possible or Alleged Violation(s) of a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a Possible or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC shall, subject to the confidentiality requirements of these Rules of Procedure, publicly post each Confirmed Violation, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation report, on its website.

    11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the Confirmed Violation or report to be posted publicly. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

    11.2 In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information (*NERC Security Guidelines for the Electricity Sector — Protecting Potentially Sensitive Information* may be used as a guide) or other Confidential Information shall be redacted in accordance with Section 1500 and not be released publicly.

11.3 Subject to redaction of Critical Energy Infrastructure Information or other Confidential Information, for each Confirmed Violation or settlement relating to a Possible Violation or an Alleged Violation, the public posting shall include the name of any relevant entity, the nature, time period, and circumstances of such Possible, Alleged or Confirmed Violation, any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity in connection with the Confirmed Violation or settlement, and sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Violation Information Review** — NERC Compliance Staff shall periodically review and analyze all reports of Possible, Alleged and Confirmed Violations to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs

1. **NERC Monitoring Program** — NERC shall have a program to monitor the Compliance Monitoring and Enforcement Program of each Regional Entity that has been delegated authority. The objective of this monitoring program shall be to ensure that the Regional Entity carries out its Compliance Monitoring and Enforcement Program in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's Compliance Monitoring and Enforcement Program. Oversight and monitoring by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, and regular evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance as described below.

1.1 **NERC Review of Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans** — NERC shall require each Regional Entity to submit for review and approval an annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan. NERC shall review each annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan and shall accept the plan if it meets NERC requirements and the requirements of the delegation agreement.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity Compliance Monitoring and

Enforcement Program implements the NERC Compliance Monitoring and Enforcement Program. The evaluation shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreement, directives in effect pursuant to the delegation agreement, approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans, required Compliance Monitoring and Enforcement Program attributes, and the NERC Compliance Monitoring and Enforcement Program procedures. These evaluations shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 3.1.6 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity Compliance Monitoring and Enforcement Program. The current procedure is contained in the NERC Audit of Regional Entity Compliance Programs, which is incorporated into these rules as **Appendix 4A**.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's Compliance Monitoring and Enforcement Program. A representative of the Regional Entity being audited will be allowed to participate in the audit as an observer.

2. **Consistency Among Regional Compliance Monitoring and Enforcement Programs** — To provide for a consistent Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program, which is incorporated into these rules of procedure as **Appendix 4C**. Any differences in Regional Entity Compliance Monitoring and Enforcement Program methods, including determination of violations and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall ensure that each of the Regional Entity Compliance Monitoring and Enforcement Programs meets these Rules of Procedure, including **Appendix 4C**, and follows the terms of the delegation agreement and the approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan.

2.2 NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program in **Appendix 4C** containing the procedures to ensure the consistency and fairness of the processes used to determine Regional Entity Compliance Monitoring and Enforcement Program findings of compliance and noncompliance, and the application of Penalties and sanctions.

2.3 NERC shall periodically conduct Regional Entity compliance manager forums. These forums shall use the results of Regional Entity Compliance Monitoring and Enforcement Program audits and findings of NERC Compliance Staff to identify and refine Regional Entity Compliance Monitoring and Enforcement Program differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Violation Disclosure** — NERC shall disclose all Confirmed Violations and maintain as confidential Possible Violations and Alleged Violations, according to the reporting and disclosure process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — NERC and Regional Entity Compliance Staff shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Regional Entity boards or a compliance panel reporting directly to the Regional Entity board will be vested with the authority for the overall Regional Entity Compliance Monitoring and Enforcement Program and have the authority to impose Penalties and sanctions on behalf of NERC, where authorized by applicable legislation or agreement. Remedial Action Directives may be issued by NERC or a Regional Entity that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert a violation of a Reliability Standard,

NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections 408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

   The appeals process will also allow for appeals to NERC of any findings of noncompliance issued by NERC to a Regional Entity for Reliability Standards and Requirements where the Regional Entity is monitored for compliance to a Reliability Standard. No monetary Penalties will be levied in these matters; however sanctions, remedial actions, and directives to comply may be applied by NERC.

7. **Conflict Disclosure** — NERC shall disclose to the appropriate governmental authorities any potential conflicts between a market rule and the enforcement of a Regional Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the NERC Compliance Monitoring and Enforcement Program, NERC and Regional Entity staff, Compliance Audit team members, and committee members shall maintain the confidentiality of information obtained and shared during compliance monitoring and enforcement processes including Compliance Investigations, Compliance Audits, Spot Checks, drafting of reports, appeals, and closed meetings.

   8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for staff and other Compliance Monitoring and Enforcement Program participants.

   8.2 Individuals not bound by NERC or Regional Entity codes of conduct who serve on compliance-related committees or Compliance Audit teams shall sign a NERC confidentiality agreement prior to participating on the committee or Compliance Audit team.

   8.3 Information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall not be distributed outside of a committee or team, nor released publicly. Other information subject to confidentiality is identified in Section 1500.

   8.4 In the event that a staff, committee, or Compliance Audit team member violates any of the confidentiality rules set forth above, the staff, committee, or Compliance Audit team member and any member organization with which the individual is associated may be subject to

appropriate action by the Regional Entity or NERC, including prohibiting participation in future Compliance Monitoring and Enforcement Program activities.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to all people who participate in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs

Each Regional Entity Compliance Monitoring and Enforcement Program shall promote excellence in the enforcement of Reliability Standards. To accomplish this goal, each Regional Entity Compliance Monitoring and Enforcement Program shall (i) conform to and comply with the NERC uniform Compliance Monitoring and Enforcement Program, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its Compliance Monitoring and Enforcement Program shall exhibit independence, meaning the Compliance Monitoring and Enforcement Program shall be organized so that its compliance monitoring and enforcement activities are carried out separately from other activities of the Regional Entity. The Compliance Monitoring and Enforcement Program shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored or other Regional Entity activities that are required to meet the Reliability Standards. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity Compliance Monitoring and Enforcement Program shall exercise the responsibility and authority in carrying out the delegated functions of the NERC Compliance Monitoring and Enforcement Program in accordance with delegation agreements and **Appendix 4C**. These functions include but are not limited to: data gathering, data reporting, Compliance Investigations, Compliance Audit activities, evaluating compliance and noncompliance, imposing Penalties and sanctions, and approving and tracking mitigation actions.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the NERC Compliance Monitoring and Enforcement Program, a Regional Entity shall not sub-delegate its Compliance Monitoring and Enforcement Program duties to entities or persons other than the Regional Entity Compliance Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or

(ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** The Regional Entity board or compliance panel reporting directly to the Regional Entity board (with appropriate recusal procedures) will be vested with the authority for conducting compliance hearings in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single segment may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Compliance Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the Regional Entity Compliance Monitoring and Enforcement Program.

6. **Regional Entity Compliance Staff Independence** — The Regional Entity Compliance Staff shall be capable of and required to make all determinations of compliance and noncompliance and determine Penalties, sanctions, and Remedial Action Directives and to review and accept Mitigation Plans and other Mitigating Activities.

    6.1 Regional Entity Compliance Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

    6.2 Regional Entity Compliance Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes (with the input of industry subject matter experts), make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

    6.3 Regional Entity Compliance Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

    6.4 Regional Entity Compliance Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure, the NERC delegation agreement and other confidentiality

agreements required by the NERC Compliance Monitoring and Enforcement Program.

6.5 Contracting with independent consultants or others working for the Regional Entity Compliance Monitoring and Enforcement Program shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals for the purpose of these Rules of Procedure shall be considered as augmenting Regional Entity Compliance Staff.

7. Use of Industry Subject Matter Experts and Regional Entity Members — Industry experts and Regional Entity members may be called upon to provide their technical expertise in Compliance Monitoring and Enforcement Program activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity Compliance Staff so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than the Compliance Staff of the Regional Entity. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Regional Entity Compliance Monitoring and Enforcement Program Content** — All approved Reliability Standards shall be included in the Regional Entity Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users within the defined boundaries of the Regional Entity. Compliance to approved Regional Reliability Standards is applicable only within the Region of the Regional Entity that submitted those particular Regional Reliability Standards for approval. NERC will identify the minimum set of Reliability Standards and Requirements to be actively monitored by the Regional Entity in a given year.

9. **Antitrust Provisions** — Each Regional Entity's Compliance Monitoring and Enforcement Program shall be structured and administered to abide by U.S. antitrust law and Canadian competition law.

10. **Information Submittal** — All Bulk Power System owners, operators, and users within the Regional Entity responsible for complying with Reliability Standards shall submit timely and accurate information when requested by the Regional Entity or NERC. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

    10.1 Each Regional Entity has the authority to collect the necessary information to determine compliance and shall develop processes for gathering data from the Bulk Power System owners, operators, and users the Regional Entity monitors.

    10.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.10 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

    10.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

    10.4 Regional Entities shall notify NERC of all Possible, Alleged and Confirmed Violations of NERC Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

    10.5 A Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan with a timeline addressing how the noncompliance will be corrected, unless an enforcement process is used that does not require a Mitigation Plan. The

Regional Entity Compliance Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

10.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all compliance data Self-Reported to the Regional Entity Compliance Monitoring and Enforcement Program.

10.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

11. **Compliance Audits of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program of proactive Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**. A Compliance Audit is a process in which a detailed review of the activities of a Bulk Power System owner, operator, or user is performed to determine if that Bulk Power System owner, operator, or user is complying with approved Reliability Standards.

11.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, Compliance Audits shall be performed on a schedule established by NERC.

11.2 Compliance Audits of Balancing Authorities, Reliability Coordinators, and Transmission Operators will include a component at the audited entity's site. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, the Compliance Audit may be either an on-site Compliance Audit or based on review of documents, as determined to be necessary and appropriate by NERC or Regional Entity Compliance Staff.

11.3 Compliance Audits must include a detailed review of the activities of the Bulk Power System owner, operator, or user to determine if the Bulk Power System owner, operator, or user is complying with all approved Reliability Standards identified for audit by NERC. The Compliance Audit shall include a review of supporting documentation and evidence used by the Bulk Power System owner, operator or user to demonstrate compliance for an appropriate period prior to the Compliance Audit.

12. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and information obtained from such processes, are to be non-public and treated as confidential in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity or FERC or another Applicable Governmental

Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis, provided, that NERC and the Regional Entities shall publish (i) schedules of Compliance Audits scheduled in each year, (ii) a public report of each Compliance Audit, and (iii) Notices of Penalty and settlement agreements. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as specific allegations or conclusions regarding Possible or Alleged Violations of Reliability Standards are not included in such disclosures.

13. **Critical Energy Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will be identified and protected from public disclosure as Critical Energy Infrastructure Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

14. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

15. **Regional Entity Hearing Process** — Each Regional Entity Compliance Monitoring and Enforcement Program shall establish and maintain a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The Regional Entity hearing process shall be conducted before the Regional Entity

board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. The Regional Entity hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single segment may veto any matter brought before the Hearing Body after recusals.

Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity hearing process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

16. **Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan** — Each Regional Entity shall annually develop and submit to NERC for approval a Regional Entity Compliance Monitoring and Enforcement Implementation Plan in accordance with **Appendix 4C** that identifies the Reliability Standards and Requirements to be actively monitored (both those required by NERC and any additional Reliability Standards the Regional Entity proposes to monitor), and how each NERC and Regional Entity identified Reliability Standard will be monitored, evaluated, reported, sanctioned, and appealed. These Regional Implementation Plans will be submitted to NERC on the schedule established by NERC, generally on or about October 1 of the preceding year. In conjunction with the annual Regional Implementation Plan, each Regional Entity must report to NERC regarding how it carried out its delegated compliance monitoring and enforcement authority in the previous year, the effectiveness of the Compliance Monitoring and Enforcement Program, and changes expected to correct any deficiencies identified. Each Regional Entity will provide its annual report on the schedule established by NERC, generally on or about February 15 of the following year.

404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users

NERC shall monitor Regional Entity compliance with NERC Reliability Standards and, if no there is no delegation agreement in effect with a Regional Entity for the geographic area, shall monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards. Industry subject matter experts may be used as appropriate in Compliance Investigations, Compliance Audits, and other Compliance Monitoring and

Enforcement Program activities, subject to confidentiality, antitrust, and conflict of interest provisions.

1. **NERC Obligations** — NERC Compliance Staff shall monitor the compliance of the Regional Entity with the Reliability Standards for which the Regional Entities are responsible, in accordance with **Appendix 4C**. NERC shall actively monitor in its annual Compliance Enforcement and Monitoring Program selected Reliability Standards that apply to the Regional Entities. NERC shall evaluate compliance and noncompliance with all of the Reliability Standards that apply to the Regional Entities and shall impose sanctions, Penalties, or Remedial Action Directives when there is a finding of noncompliance. NERC shall post all violations of Reliability Standards that apply to the Regional Entities as described in the reporting and disclosure process in **Appendix 4C**.

   In addition, NERC will directly monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the Compliance Enforcement Authority described in **Appendix 4C**. Compliance matters contested by Bulk Power System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Compliance Audit of the Regional Entity** — NERC shall perform a Compliance Audit of each Regional Entity responsible for complying with Reliability Standards at least once every three years. NERC shall make an evaluation of compliance based on the information obtained through the Compliance Audit. After due process is complete, the final Compliance Audit report shall be made public in accordance with the reporting and disclosure process in **Appendix 4C**.

3. **Appeals Process** —Any Regional Entity or Bulk Power System owner, operator or user found by NERC, as opposed to a Regional Entity, to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC

The NERC Compliance and Certification Committee shall establish and implement a process to monitor NERC's compliance with the Reliability Standards that apply to NERC. The process shall use independent monitors with no conflict of interest, real or perceived, in the outcomes of the process. All violations shall be made public according to the reporting and disclosure process in **Appendix 4C**. The Compliance and Certification Committee will also establish a procedure for monitoring NERC's compliance with its Rules of Procedure for the Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs. Such procedures shall not be used to circumvent the appeals processes established for those programs.

406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of its Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the NERC Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entity Compliance Monitoring and Enforcement Programs and the effectiveness of the programs in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with **Appendix 4C**.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the NERC Compliance Monitoring and Enforcement Program, the administrators of the NERC Compliance Monitoring and Enforcement Program shall provide a written response and plan to the Board within 30 days of the release of the final audit report.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions and Remedial Action Directives that are specified by a Regional Entity Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination is supported by a sufficient record compiled by the Regional Entity, is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance and directions issued by NERC pursuant to the delegation agreement, and is consistent with Penalties, sanctions and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Compliance Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable

Governmental Authority, a "Notice of Penalty" and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity or a Regional Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity Compliance Monitoring and Enforcement Program audit finding, may do so by filing a notice of the challenge with NERC's director of enforcement no later than 21 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Regional Entity Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of challenge, the NERC director of enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — The NERC Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's director of enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, the NERC Compliance Monitoring and Enforcement Program staff may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Compliance Committee may invite representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program to appear before the Compliance Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Regional Entity Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the Compliance Enforcement Authority, or an owner, operator or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Regional Entity Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's director of enforcement, with copies to the Regional Entity and any other Participants in the Regional Entity Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Regional Entity Hearing Body.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Regional Entity Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Regional Entity Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Regional Entity shall file the entire record of the Regional Entity Hearing Body proceeding with NERC's director of enforcement, with a copy to the Participant filing the notice. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Regional Entity Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The Registered Entity filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Regional Entity Hearing Body, the responses, and any reply filed with NERC. At its discretion, the Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Regional Entity Hearing Body to appear before the Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Regional Entity Hearing Body granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding. Appeals of decisions of Regional Entity Hearing Bodies granting or denying motions to intervene in Regional Entity Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement, and the request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standard,* Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Regional Entity Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Regional Entity Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees, for decision, a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Regional Entity Hearing Body to the Board of Trustees shall be considered and disposed of by the Compliance Committee.

2. The Compliance Committee may accept or reject a certification of a question for decision. If the Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Regional Entity Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Compliance Committee. The Compliance Committee may also request, or provide an opportunity for, the NERC compliance operations department, the NERC compliance enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda as are filed in accordance with the schedule, the Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Compliance Committee's written decision on the certified question, the Regional Entity Hearing Body shall proceed to complete the hearing in accordance with the Compliance Committee's decision.

5. The Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Regional Entity Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Regional Entity Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity Compliance Monitoring and Enforcement Program. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in

accordance with, as applicable to the particular decision, Sections 5.8, 5.9 and 6.5 of Appendix 4C.

414. Appeals of Decisions of Regional Entity Hearing Bodies Granting or Denying Motions to Intervene in Regional Entity Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Regional Entity Hearing Body proceeding, and the Regional Entity Compliance Staff or any other Participant in the Regional Entity Hearing Body proceeding may appeal a decision of the Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding, in either case by filing a notice of appeal with the NERC director of enforcement, with copies to the Regional Entity Clerk, the Regional Entity Hearing body, the Hearing Officer, the Regional Entity Compliance Staff, and all other Participants in the Regional Entity Hearing Body proceeding, no later than seven (7) days following the date of the Regional Entity Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Regional Entity Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Regional Entity Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Regional Entity Clerk shall transmit to the NERC director of enforcement copies of all pleadings filed in the Regional Entity Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Regional Entity Hearing Body, the Regional Entity Compliance Staff, and any other Participants in the Regional Entity Hearing Body proceeding, may each file a response to the notice of appeal with the NERC director of enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Regional Entity Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC director of enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Compliance Committee. The NERC director of enforcement shall provide copies of the notice of appeal and any responses and replies to the Compliance Committee. The Compliance Committee shall issue a written decision on the

appeal; provided, that if the Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Regional Entity Hearing Body granting or denying the motion to intervene shall stand. The NERC director of enforcement shall transmit copies of the Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Compliance Committee, to the Regional Entity Clerk, the Regional Entity Hearing Body, the entity filing the notice of appeal, the Regional Entity Compliance Staff, and any other Participants in the Regional Entity Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Compliance Committee on an appeal of a Regional Entity Hearing Body decision granting or denying a motion to intervene in a Regional Entity Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Compliance Committee to FERC or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Refer to Section 507.

(c) Multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. This includes those

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

entities that satisfy the criteria established in the NERC provisional Certification process. The NERC programs shall:

2.1 Evaluate and certify the competency of entities performing reliability functions. The entities presently expected to be certified include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Evaluate and certify each applicant's ability to meet the requirements for Certification.

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements, and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual,* Sections V and VI, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.8.d.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

      2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification

Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with their members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

    2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

    3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

    3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

    3.3 Regional Entities shall notify NERC of all Certification applicants.

    3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

    3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

        3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to

support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be posted by NERC for public viewing.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every

recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. Any entity seeking to register as a JRO must submit a written agreement with its members or related entities for all Requirements/sub-Requirements for the function(s) for which the entity is registering for and takes responsibility for, which would otherwise be the responsibility of one or more of its members or related entities. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the JRO Registration.

2. The JRO Registration data must include the same Registration information as a normal compliance Registration entry. The JRO is responsible for providing all of the information and data, including submitting reports, as needed by the Regional Entity for performing assessments of compliance.

3. The Regional Entity shall notify NERC of each JRO that the Regional Entity accepts. The notification will identify the point of contact and the functions(s) being registered for on behalf of its members or related entities.

4. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs. This document shall contain a list of each JRO's members or related entities and the function(s) for which the JRO is registered for that member(s) or related entity(s). It is the responsibility of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

5. The Regional Entity may request clarification of any list submitted to it that identifies the members of the JRO and may request such additional information as the Regional Entity deems appropriate.

6. The Regional Entity's acceptance of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the JRO will meet the Registration requirements of Section 501(1.4).

7. NERC shall maintain, and post on its website, a JRO registry listing all JRO Registrations that have been reviewed and accepted by the Regional Entity. The posting shall identify the JRO entity taking compliance responsibilities for itself and its members.

8. The JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

9. Nothing in Section 507 shall preclude a member of a JRO, a related entity, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the member or other entity is registering. A JRO member or related entity that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the JRO of its Registration.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.

2. Each CFR or each individual entity within a CFR must identify a point of contact that is responsible for providing information and data, including submitting reports as needed by the Regional Entity related to the CFR Registration.

3. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts.

4. NERC or the Regional Entity may request clarification of any list submitted to it that identifies the compliance responsibilities of the CFR and may request such additional information as NERC or the Regional Entity deems appropriate.

5. The Regional Entity's acceptance of that CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the CFR will meet the Registration requirements of Section 501(1.4).

6. NERC shall maintain, and post on its website, a CFR registry listing all CFR Registrations that have been accepted by NERC or by a Regional Entity. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

7. The point of contact shall inform the Regional Entity of any changes to an existing CFR. The Regional Entity shall promptly notify NERC of each such revision.

8. In the event of a violation of a Reliability Standard or of a Requirement/sub-Requirement of a Reliability Standard for which an entity of a CFR is registered, that entity shall be identified in the Notice of Alleged Violation and shall be assessed the sanction or Penalty in accordance with the NERC Sanctions Guidelines. In the event a Regional Entity is not able to determine which entity(ies) is responsible for a particular Reliability Standard, or Requirements/sub-Requirements thereof that has been violated, the Regional Entity shall investigate the noncompliance in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*, to determine the entity(ies) to which the Regional Entity shall to issue the sanction or Penalty for the violation.

9. Nothing in Section 508 shall preclude an entity registered in a CFR, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the entity is registering. An entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the point of contact of its Registration.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION

601. Scope of Personnel Certification

Maintaining the reliability of the Bulk Electric System through implementation of the Reliability Standards requires skilled, trained and qualified system operators. The Personnel Certification Program provides the mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the Bulk Electric System. The Personnel Certification awards system operator Certification Credentials to individuals who demonstrate that they have attained essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations. NERC, as the ERO, will ensure skilled, trained, and qualified system operators through the Personnel Certification Program.

Except as necessary to obtain approval of the Rules of Procedure, the NERC Personnel Certification Governance Committee (PCGC) is the governing body that establishes the policies, sets fees, and monitors the performance of the Personnel Certification Program for system operators.

602. Structure of ERO Personnel Certification Program

1. The NERC Personnel Certification Program shall be international in scope.
2. The PCGC shall (1) be able to independently exercise decision-making for all matters pertaining to Certification, (2) include individuals from the discipline being certified and whose composition addresses the needs of the users of the program (e.g., employers, regulators, etc.), and (3) have representation for each specialty or level within a discipline.
3. NERC shall maintain a nominating process for membership in the governing body. Nominations shall be open to all interested parties and self-nominations shall be accepted. The NERC Board of Trustees shall appoint members to the governing body from among those nominated. The members of the governing body shall serve at the pleasure of the Board.
4. The PCGC shall have control over the matters related to the Personnel Certification and re-Certification Programs listed below, without being subject to approval by any other body.

    4.1 Policies and procedures, including eligibility requirements and application processing.

    4.2 Requirements for personnel Certification, maintaining Certification, and re-Certification.

    4.3 Examination content, development, and administration.

    4.4 Examination cut score.

4.5 Grievance and disciplinary processes.

4.6 Governing body and subgroup(s)' meeting rules including agenda, frequency, and related procedures.

4.7 Subgroup(s) appointments and work assignments.

4.8 Publications about personnel Certification and re-Certification.

4.9 Setting fees for application, and all other services provided as a part of the personnel Certification and re-Certification activities.

4.10 Program funding, spending, and budget authority. Financial matters related to the operation of the program shall be segregated from other NERC activities.

5. The Personnel Certification Program shall utilize written procedures for the selection of members of the governing body that prohibit the governing body from selecting a majority of its successors.

6. The Personnel Certification Program shall be separate from the accreditation and education functions of NERC in related disciplines.

7. No member of the PCGC or staff member working with the Personnel Certification Program governing body shall have or exercise any authority or responsibility for compliance matters related to Reliability Standards concerning personnel Certification.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will

investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

   5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

3.2. Probation: A letter will be sent from NERC to the offender specifying:

3.2.1. The length of time of the probationary period (to be determined by the PCGC).

3.2.2. Credential will remain valid during the probationary period.

3.2.3. The probationary period does not affect the expiration date of the current certificate.

3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

3.3.1. The length of time of the probationary period (to be determined by the PCGC).

3.3.2. Credential is no longer valid.

3.3.3. Successfully passing an exam will be required to become recertified.

3.3.4. An exam will not be authorized until the revocation period expires

3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing Mechanisms

1. The Personnel Certification Program shall utilize reliable testing mechanisms to evaluate individual competence in a manner that is objective, fair to all candidates, job-related, and based on the knowledge and skill needed to function in the discipline.

2. The Personnel Certification Program shall implement a formal policy of periodic review of the testing mechanisms to ensure ongoing relevance of the mechanisms to knowledge and skill needed in the discipline.

3. The Personnel Certification Program shall utilize policies and procedures to ensure that all test administration and development materials are secure and demonstrate that these policies and procedures are consistently implemented.

4. The Personnel Certification Program shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted in the psychometric community as being fair and reasonable.

5. The Personnel Certification Program shall conduct ongoing studies to substantiate the reliability and validity of the testing mechanisms.

6. The Personnel Certification Program shall utilize policies and procedures that govern how long examination records are kept in their original format.

7. The Personnel Certification Program shall demonstrate that different forms of the testing mechanisms assess equivalent content and that candidates are not penalized for taking forms of varying difficulty.

607. Public Information About the Personnel Certification Program

1. The Personnel Certification Program shall maintain and publish publicly a System Operator Certification Program Manual describing the procedures used in examination construction and validation; all eligibility requirements and determination; fees; and examination administration documents, including: reporting of results, re-Certification requirements, and disciplinary and dispute resolution.

2. The Personnel Certification Program shall maintain and publish publicly a comprehensive summary or outline of the information, knowledge, or functions covered by each examination.

3. The Personnel Certification Program shall publish publicly and make available at least annually a summary of Certification activities for the program, including at least the following information: number of examinations delivered, the number passed, the number failed, and the number certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The Personnel Certification Program:

1. Shall not discriminate among applicants as to age, gender, race, religion, national origin, disability, or marital status and shall include a statement of non-discrimination in announcements of the program.

2. Shall comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services.

3. Shall make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants.

4. Shall implement a formal policy for the periodic review of eligibility criteria and application procedures to ensure that they are fair and equitable.

5. Shall provide competently proctored examination sites.

6. Shall uniformly report examination results to applicants in a timely manner.

7. Shall give applicants failing the examination information on general content areas of deficiency.

609. Responsibilities to the Public and to Employers of Certified Practitioners

The Personnel Certification Program:

1. Shall demonstrate that the testing mechanisms adequately measure the knowledge and skill required for entry, maintenance, and/or advancement in the profession for each position to be certified.

2. Shall award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable.

3. Shall maintain, in an electronic format, a current list of those persons certified in the programs and have policies and procedures that delineate what information about a Credential holder may be made public and under what circumstances.

4. Shall have formal policies and procedures for discipline of a Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

5. Shall demonstrate that any title or Credential awarded accurately reflects or applies to the practitioner's daily occupational or professional duties and is not confusing to employers, consumers, regulators, related professions, and/or other interested parties.

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

   1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

   1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

   1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

   1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

   1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems, operational readiness of the affected Regional Entities for the upcoming season

shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Maintaining the reliability of the Bulk Electric System through implementation of the Reliability Standards requires informed and trained personnel. The training and education program will provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the Bulk Electric System.

NERC shall develop and maintain training and education programs for the purpose of establishing training requirements, developing materials, and developing training activities. The target audience of the training and education programs shall be Bulk Power System operating personnel including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, training personnel, and other personnel directly responsible for complying with NERC Reliability Standards who, through their actions or inactions, may impact the real-time, or day-ahead reliability of the Bulk Power System.

NERC shall also develop and provide appropriate training and education for industry participants and regulators affected by new or changed Reliability Standards or compliance Requirements.

To accomplish those objectives:

1. NERC shall periodically conduct job task analyses for targeted Bulk Power System personnel to ensure that the training program content is properly aligned to the job tasks performed by those personnel.

2. NERC shall develop and maintain personnel training program curriculum requirements based on valid job-task analysis.

3. NERC shall periodically conduct performance surveys to determine the effectiveness of the training program and identify areas for further training development and improvement.

4. NERC shall develop training and education materials and activities to assist Bulk Power System entities implementing new or revised Reliability Standard Requirements or other NERC-related changes.

5. NERC shall develop and provide training to people who participate in NERC and Regional Entity evaluations, audits, and investigations for the Compliance Monitoring and Enforcement Program, Organization Certification Program, and the continuing education program.

902. Continuing Education Program

NERC shall develop and maintain a continuing education program to foster the improvement of training and to promote quality in the training programs used by and

implemented by Bulk Power System entities. The program shall approve or accredit those activities and entities meeting NERC continuing education requirements.

1. NERC shall develop and implement continuing education program requirements that promote excellence in training programs and advance improved performance for Bulk Power System personnel identified in Section 901.

2. NERC shall develop and maintain a process to approve or accredit continuing education Providers and activities seeking approval or accreditation and meeting NERC-approved continuing education requirements.

3. NERC shall perform periodic audits on continuing education Providers and training activities to ensure that the approved or accredited Providers and training activities satisfy NERC continuing education requirements.

4. NERC shall develop and maintain an appeals process for disputed application reviews, interpretations of guidelines and standards, probation or suspension of NERC-approved Provider status, or Continuing Education Hour disputes.

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electric Sector Information Sharing and Analysis Center (ESISAC)

    1.1 NERC shall serve as the electricity sector's sector coordinator and operate its Information Sharing and Analysis Center to gather information and communicate security-related threats and incidents within the sector, with United States and Canadian government agencies, and with other Critical Infrastructure sectors.

    1.2 NERC shall improve the capability of the ESISAC to analyze security threats and incident information and provide situational assessments for the electricity sector and governments.

    1.3 NERC shall work closely with the United States Department of Homeland Security, Department of Energy, Natural Resources Canada, and Public Safety and Emergency Preparedness Canada.

    1.4 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.5 NERC shall fill the role of the Electricity Sector Coordinating Council and coordinate with the Government Coordinating Council.

    1.6 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, the other ISACs, and the National Infrastructure Advisory Committee.

    1.7 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, and recognizing that mitigation and recovery can be practical alternatives to prevention.

2.2 NERC shall keep abreast of the changing threat environment through collaboration with government agencies.

2.3 NERC shall develop criteria to identify critical physical assets and Critical Cyber Assets, assess security threats, identify risk assessment methodologies, and assess effectiveness of physical and cyber protection measures.

2.4 NERC shall enhance and maintain the Bulk Power System critical spare transformer program, encourage increased participation by asset owners, and continue to assess the need to expand this program to include other critical Bulk Power System equipment.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness and respond to the needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters; work with DOE and DHS to implement the National Infrastructure Protection Plan, as applicable to the electricity sector; and coordinate this work with PSEPC.

2.10 NERC shall improve methods to better assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

2.11 NERC shall assess the results of vulnerability assessments and enhance the security of system control and data acquisition (SCADA) and process control systems by developing methods to detect an emerging cyber attack and the means to mitigate impacts on the Bulk Power Systems.

2.12 NERC shall work with the National SCADA Test Bed and the Process Control Systems Forum to accelerate the development of technology that

will enhance the security, safety, and reliability of process control and SCADA systems.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources

provided for in the budget to carry out the ERO program responsibilities; explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding requirement (including Regional Entity costs for delegated functions), and (3) the

mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[3] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional Entity will collect directly from the Load-Serving Entities or as otherwise

[3] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may

request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional

information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted

on NERC's website at approximately the same time that notice is given to committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

4. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

5. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the "Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or

any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement in a form approved by NERC's Board of Trustees.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief

executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Confirmed Violations** — Nothing in this Section 1500 shall prohibit the disclosure of a violation at the point when the matter is filed with an Applicable Governmental Authority as a Notice of Penalty, the "violator" admits to the violation, or the alleged violator and NERC or the Regional Entity reach a settlement regarding the violation.

2. **Compliance Information** — NERC and the Regional Entities are authorized to exchange Confidential Information related to evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses information determined to be confidential may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500

precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information,"

"aggregating" or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is

reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

    2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

    2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

    2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix 5A

Organization Registration and Certification Manual

Effective Date: ~~March 19, 2015~~DATE

RELIABILITY | ACCOUNTABILITY

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Section I — Executive Summary

Overview

The purpose of this document is twofold: (1) to define the process utilized in the Organization Registration Program for identifying which functional entities must register as owners, operators, and users of the Bulk Power System (BPS) for compliance with Reliability Standards; and (2) to define the process utilized in the Organization Certification Program for certifying the following entities: Reliability Coordinator (RC), Balancing Authority (BA), and Transmission Operator (TOP). The North American Electric Reliability Corporation (NERC) Compliance and Certification Committee (CCC) is responsible for approving and forwarding these processes to the NERC Board of Trustees (Board) for its approval. Where a proposal for revisions to these processes comes to the Board from sources other than the CCC, the Board will seek the concurrence of the CCC before taking action on the proposal.

To Whom Does This Document Apply?

All industry participants responsible for or intending to be responsible for, the following functions must register with NERC through the Organization Registration process. The entities are defined in the NERC *Statement of Compliance Registry Criteria*, set forth in **Appendix 5B** to the NERC Rules of Procedure (ROP), with responsibilities designated by the individual Reliability Standards or by a sub-set list of the otherwise applicable Reliability Standards. Such sub-set list will specify the Reliability Standards and may specify Requirements/sub-Requirements by NERC, in which case the entity will be responsible for compliance with only such sub-set list, in accordance with **Appendix 5B** to the NERC ROP.

	Entities that Must Register	Entities that Need to be Certified
Reliability Coordinator (RC)	√	√
Transmission Operator (TOP)	√	√
Balancing Authority (BA)	√	√
Planning Authority (PA)	√	
Transmission Planner (TP)	√	
Transmission Service Provider (TSP)	**√**	
Transmission Owner (TO)	**√**	
Resource Planner (RP)	**√**	
Distribution Provider (DP)	**√**	
Generator Owner (GO)	**√**	
Generator Operator (GOP)	**√**	
~~Load-Serving Entity (LSE)~~	~~**√**~~	
Reserve Sharing Group (RSG)	√	

When did These Processes Begin?

The initial Registration process began in January of 2006. Registration of new entities is an ongoing process. If a Registered Entity's information changes, these changes must be submitted to the applicable Regional Entity(s).

Certification is ongoing for new entities in accordance with Section IV of this manual.

Where to Access and Submit Form(s)?

Registration and Certification forms are provided on each Regional Entity's website. Completed forms are to be sent electronically to the Compliance and Certification Manager of the applicable Regional Entity(s). It is desirable

that entities operate within a single Regional Entity Region; however, if an entity operates in more than one Region, separate Registration applications must be completed and submitted to each of the Regional Entities.

Service

Unless otherwise provided, service may be made by personal delivery, email, deposit in the United States mail properly addressed with first class postage prepaid, registered mail properly addressed with postage prepaid or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made.

Roles and Responsibilities

The following is a high-level overview of the roles and responsibilities in the Registration and Certification processes:

NERC

1. Oversight of entity processes performed by the Regional Entities, including:
   a. Governance per the Regional Entity's delegation agreement with NERC.
   b. Coordination of process execution when an entity is registering and/or certifying with multiple Regional Entities.
2. Manage each entity's NERC Compliance Registry identification number (NERC ID) including:
   a. Sending a Registration or Certification letter that contains the NERC ID to the applicable Regional Entity(ies) for review and approval. If the Regional Entity(ies) agrees with all the information provided, it will notify NERC to issue the NERC ID to the Registered Entity and will send a copy of the notification being provided to the Regional Entity(ies).
   b. Ensuring each Registered Entity has only one NERC ID for all Regional Entities in which registered.
3. Make modeling changes based on Registration information.
4. Maintain accurate Registration and Certification records including granting Certification certificates for the Registered Entity(ies) responsible for compliance (including Joint Registration Organization (JRO)/Coordinated Functional Registration (CFR)).
5. Maintain published up-to-date list of Registered Entities (i.e. the NERC Compliance Registry (NCR)) on the NERC website. NERC maintains the NCR, which identifies each Registered Entity and the applicable functional categories for which it is registered.
6. Lead panel reviews in accordance with **Appendix 5A,** *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

Regional Entity

1. Performs data collection and Mapping of BPS Facilities and those Facilities that have a material impact on the BPS within its Regional Entity defined reliability Region boundaries.
2. Approves or disapproves entity Registration applications.
3. Reviews entity Certification applications for completeness.
4. Notifies NERC of entities registered with the Regional Entity.
5. Approves or denies Certification Team (CT) recommendations and notifies the entity and NERC of the decision.

6. Provides leadership to the CT throughout the Certification process.

Entity Submitting the Application

1. Completes and submits Registration and/or Certification application.
2. Submits updates to Registration and/or Certification information as necessary and/or requested.
3. Responds to Regional Entity and/or NERC questions pertaining to Registration and/or Certification.
4. Provides documentation or other evidence requested or required to verify compliance with Certification requirements.

Section II — Introduction to Organization Registration and Organization Certification Processes

The processes utilized to implement the Organization Registration and Organization Certification Programs are administered by each Regional Entity. Pursuant to its delegation agreement with NERC, each Regional Entity is responsible for registering and certifying industry participants within its Regional Entity reliability Region boundaries. Each Regional Entity must use the following NERC processes.

Organization Registration — Entities Required to Register

All industry participants responsible for one or more of the functions below must register for each function through the Organization Registration Program. These entities are defined in the NERC *Statement of Compliance Registry Criteria*.

- RC
- TOP
- BA
- PA
- TP
- TSP
- TO
- RP
- DP
- GO
- GOP
- ~~LSE~~
- RSG

The Registration procedure is in Section III of this manual.

Organization Certification

All Registered Entities registered in the NCR for the RC, TOP, and/or BA functions shall be certified. Certification requires the Registered Entity to start operation within 12 months of being NERC certified. This Certification process is described in Section IV of this manual.

Section III — Organization Registration Process

Purpose and Scope

The purpose and scope of this process is to provide guidance on how a user, owner, and/or operator of the BPS should be registered in the NCR.

Overview

Section 39.2 of the Commission's regulations, and Title 18 of the C.F.R. § 39.2, requires each owner, operator, and user of the BPS to be registered with NERC and to comply with approved Reliability Standards.

Owners, operators, and users of the BPS will be registered by function(s) and are:

1. Responsible for compliance with all applicable Requirements/sub-Requirements within Reliability Standards approved by Applicable Governmental Authorities, for the applicable functions for which the Registered Entity is registered, except to the extent that an entity is granted a sub-set list of applicable Reliability Standards, which specifies the Reliability Standards and may specify Requirements/sub-Requirements by NERC, in which case the entity will be responsible for compliance with only such sub-set list; and,
2. Subject to the compliance monitoring and enforcement requirements of Section 400 of the ROP.

See Figure 1A Organization Registration Process Overview.

A. Organization Registration Process

1. Applicable entities shall begin the Registration process by submitting a completed Registration application to the Regional Entity(ies) of the reliability Region(s) where the entity intends to perform its function(s) (Registration forms are provided on each Regional Entity's website).
    a. At any time, an entity may recommend in writing, with supporting documentation, to the Regional Entity(ies) that an entity be added to or removed from the Compliance Registry.
    b. The Registration process for an entity may also be initiated by a Regional Entity, NERC, or Applicable Governmental Authority.
    c. With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.
    d. At any time, an entity whose registration is at issue may request expedited treatment and waiver of applicable timelines. NERC, in its sole discretion, shall determine if such a request will be granted and alternative timelines. NERC's decision is not a final decision that is subject to appeal.
2. NERC shall coordinate Registration of entities that are required to register with multiple Regional Entities in order to ensure consistency of the Registration process.
3. For entities that are required to be certified, the applicable Regional Entity(ies) shall ensure that the Registration information provided is accurate for updating the NCR per items 4 through 12 below and notifies the entity to initiate the Certification process per Section IV of this manual.
4. Entities that have a NERC ID shall use it on the form.

a. If an entity does not have a NERC ID, NERC shall assign one.

b. An entity responsible for more than one function will use a single NERC ID.

5. Regional Entities shall evaluate the submitted information and determine if the information is complete/correct. If the information is not complete/correct, the entity will be notified to complete/correct or clarify the Registration information.

6. A single entity must register for all functions that it performs itself. In addition, that entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register and, thereby, accept on behalf of such members or related entities all compliance responsibility for all Requirements/sub-Requirements of Reliability Standards applicable to that function or those functions including reporting requirements.(ROP Section 507)

7. Multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function.(ROP Section 508)

8. In completing the Regional Entity responsibilities for the Registration process, the following are key items the Regional Entity must verify:

   a. That Regional Entity registrations meet the geographical and electrical Registration boundaries requirements of the ROP Section 501(1.4).

   b. The Registration submission includes all data requested by NERC that is necessary for accurately identifying and contacting the Registered Entity.

9. The Regional Entity shall forward all Registration information to NERC for inclusion of an entity on the NCR:

   a. If the Registration determination involves (i) the materiality test set forth in the notes in **Appendix 5B**, *Statement of Compliance Registry Criteria*; (ii) a sub-set list of Reliability Standards (which specifies Requirements and may specify sub-Requirements);[1] or (iii) a dispute by an entity whose registration status is at issue regarding the Regional Entity's application of **Appendix 5B**, *Statement of Compliance Registry Criteria*, a NERC-led review panel will be convened in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D.

   b. Within five business Days of a Registration determination by NERC or the NERC-led review panel, as applicable, NERC will forward the proposed additions or changes to the NCR to the Regional Entity for review and comment.

   c. The Regional Entity has five business Days to respond to the proposed changes.

   d. If NERC does not receive any comments, the NCR will be revised. If NERC does receive comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly.

10. NERC updates the NCR and notifies the applicable Registered Entity(ies) within five business Days of the update.

[1] If NERC has established clearly defined criteria for eligibility for a sub-set list of applicable Reliability Standards and has identified the sub-set list that may apply to similarly situated entities, such criteria shall govern the applicability of such sub-set list and such a matter shall not proceed to the NERC-led review panel, unless there is a dispute by the entity whose sub-set list treatment is at issue. (See, e.g., UFLS-Only DPs.)

11. The Registered Entity may appeal the final registration determination by NERC in accordance with the ROP Section 500 and Section V of **Appendix 5A**.

12. The NCR shall be dynamic and will be revised as necessary to take account of changing circumstances such as corrections, revisions, and or deletions. Per the Regional Entity's delegation agreement, the Regional Entity will take any recommendation received under Section 1.a, and other applicable information, under advisement as it determines whether an entity should be on the NCR.

    a. Each Registered Entity identified in the NCR shall notify its corresponding Regional Entity and/or NERC of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards. (ROP Section 400).

    b. Each Regional Entity has an independent obligation, even in the absence of a notification by a Registered Entity, to review and submit updates to the NCR to NERC, consistent with the procedures in this Section III, with appropriate notification to the affected entities, to the extent the Regional Entity is aware of, or possesses information that the NCR should be updated. These updates include, but are not limited to, conditions on which the sub-set list are no longer applicable, or where a new and emerging risk to reliability is identified that changes the basis upon which the entity was deactivated, deregistered, or upon which a sub-set list of requirements was made applicable, in addition to deactivation[2] of entities that no longer meet the applicable registration thresholds. This does not excuse the Registered Entity from its obligation to provide such required notifications.

13. Entities registered or subject to registration as a DP that qualify as Underfrequency Load Shedding (UFLS)-Only DPs shall submit Registration information to the Regional Entity. The UFLS-Only DP shall be subject only to the sub-set list of Reliability Standards identified in **Appendix 5B**. Within 50 Days of the entity's submission of the Registration information to the Regional Entity, the Regional Entity shall issue a decision as to whether UFLS-Only DP treatment is appropriate. If the Regional Entity concludes that it is, then the Regional Entity shall forward the information to NERC and NERC will forward the proposed additions or changes to the NCR to the Regional Entity for review and comment. The Regional Entity has five business Days to respond to the proposed changes. If NERC does not receive any comments, the NCR will be revised. If NERC receives comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly. NERC updates the NCR and notifies the applicable Registered Entity(ies) within five business Days of the update. If the entity whose registration is at issue does not agree with the Regional Entity's decision regarding UFLS-Only DP treatment, the entity may, within 30 Days of issuance of the decision, seek review by the NERC-led review panel in **Appendix 5A**, *Organization Re*gistration *and Organization Certification Manual*, Section III.D. If the entity whose registration is at issue does not agree with the determination of the NERC-led review panel, the entity may file an appeal with the NERC Board Compliance Committee (BOTCC) in accordance with the provisions set forth in Section V of this **Appendix 5A**.

13. The Registered Entity may file a registration appeal with the NERC BOTCC in accordance with the provisions set forth in Section V of **Appendix 5A** if it does not agree with the determination of the NERC-led review panel.

14. NERC may extend the timelines for good cause shown. Requests should be sent to the Director of Compliance.[3] NERC shall notify the Registered Entity and the Regional Entity of such time extensions.

[2] See Figure 1B: Deactivation Process Overview

[3] References to the term Director of Compliance in the NERC ROP should be read to include an equivalent position.

B. Deactivation Process

1. The term Deactivation refers to removal of an entity from the NCR for a specific functional category.
2. As a result of Deactivation, the entity is no longer subject to any prospective compliance obligations with respect to Reliability Standards applicable to that functional category.
3. If all functional categories have been deactivated for a given entity, such entity would be deregistered and removed from the NCR. However, the entity's compliance history will be retained. In its letter notifying the entity of its Deactivation or deregistration, as applicable, NERC will notify the entity of the required retention period, in accordance with the NERC ROP.
4. A Registered Entity may submit a request for Deactivation and supporting information to the Regional Entity at any time. Such information shall include:
    a. Entity name and NCR ID number;
    b. Functions for which Deactivation is requested; and
    c. The basis on which Deactivation is requested, including supporting documentation, which may be limited to an attestation, if appropriate.
5. The Regional Entity shall request any additional information from the Registered Entity within 10 Days of receipt of the request for Deactivation.
6. The Registered Entity shall provide the additional information within 20 Days of its request for Deactivation.
7. The Regional Entity will issue a decision within 50 Days of the date of receipt of all requested information from the Registered Entity.
8. If the Regional Entity agrees with the request for Deactivation, it shall forward its Deactivation determination to NERC within five business Days of issuance of the decision.
9. If NERC accepts the Deactivation determination and the Registered Entity agrees with the determination, NERC will forward within five business Days of receipt of the Deactivation determination from the Regional Entity, the proposed additions or changes to the NCR to the Regional Entity for review and comment.
    a. The Regional Entity has five business Days to respond to the proposed changes.
    b. If NERC does not receive any comments, the NCR will be revised. If NERC receives comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly.
10. If the Regional Entity or NERC does not agree with the request for Deactivation, the Registered Entity may seek review by the NERC-led review panel in **Appendix 5A**, *Organization Registration and Organization Certification Manual,* Section III.D.
11. If the Deactivation determination involves (i) the materiality test set forth in the notes in **Appendix 5B**, *Statement of Compliance Registry Criteria*; (ii) a determination that a sub-set list of Reliability Standards (which will specify Reliability Standards and may specify Requirements/sub-Requirements) should apply as an alternative to Deactivation;[4] or (iii) the Registered Entity disagrees with the Regional Entity determination, the determination will be submitted to the NERC-led review panel process in **Appendix**

[4] If NERC has established clearly defined criteria for eligibility for a sub-set list of applicable Reliability Standards and has identified the sub-set list that may apply to similarly situated entities, such criteria shall govern the applicability of such sub-set list and such a matter shall not proceed to the NERC-led review panel, unless there is a dispute by the entity whose sub-set list treatment is at issue. (See, e.g., UFLS-Only DPs.)

5A, *Organization Registration and Organization Certification Manual,* Section III.D within 30 Days after issuance of the determination.

12. If the NERC-led review panel approves the request for Deactivation, NERC will forward within five business Days of the panel decision, the proposed additions or changes to the NCR to the Regional Entity for review and comment.

    a. The Regional Entity has five business Days to respond to the proposed changes.

    b. If NERC does not receive any comments, the NCR will be revised. If NERC receives comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly.

13. The Registered Entity may file a registration appeal with the NERC BOTCC in accordance with the provisions set forth in Section V of **Appendix 5A** if it does not agree with the determination of the NERC-led review panel.

14. NERC may extend the timelines for good cause shown. Requests should be sent to the Director of Compliance. NERC shall notify the Registered Entity and the Regional Entity of such time extensions.

C. Reactivation Process

1. NERC maintains the NCR, which identifies each Registered Entity and the applicable functional categories for which it is registered.

2. The term Reactivation refers to re-registration pursuant to the NERC ROP Section 500 and **Appendices 5A and 5B** of an entity to the NCR for a specific functional category or the revocation of, or additions to, a sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements) that has been granted to an entity. Reactivation may be initiated by NERC, a Regional Entity or an entity with respect to such entity's own functional categories or sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements).

3. Reactivation shall be governed by the procedures in the NERC ROP Section 500 and Section III.A and, as applicable, Section III.D of this **Appendix 5A**.

4. As a result of Reactivation, and consistent with the implementation plan to be developed pursuant to this paragraph, the entity shall prospectively comply with all Reliability Standards applicable to that functional category, or with the sub-set list specified in the Reactivation determination, unless otherwise notified. Within 30 days of a final Reactivation determination, the entity shall submit a proposed implementation plan to the Regional Entity detailing the schedule for complying with any Reliability Standards applicable to the Reactivation. The Regional Entity and Registered Entity shall confer to agree upon such schedule. If the Regional Entity and Registered Entity are unable to agree on the implementation plan, the Regional Entity shall notify the NERC Director of Compliance of the disagreement, and shall provide statements of the Regional Entity's and the Registered Entity's positions, and NERC shall specify a reasonable implementation schedule.

5. The entity's prior compliance history will be retained and shall apply with respect to the Reactivation. In its letter notifying the entity of its Reactivation, NERC will notify the entity of its registration in accordance with the NERC ROP.

6. The Registered Entity may file a registration appeal with the NERC BOTCC in accordance with the provisions set forth in Section V of **Appendix 5A** if it does not agree with the determination of the NERC-led review panel.

7. NERC may extend the timelines for good cause shown. Requests should be sent to the Director of Compliance. NERC shall notify the Registered Entity and the Regional Entity of such time extensions.

D. NERC-led Review Panel

1. NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, to vet requests for Deactivation of, or decisions not to register, an entity that meets Sections I through IV of the Registry Criteria or requests to add an entity that does not meet (i.e., falls below) Sections I through IV of the Registry Criteria, as well as disputes regarding the application of Sections I through IV of the Registration Criteria and requests for a sub-set list of applicable Reliability Standards (which may specify the Requirements/sub-Requirements).

    a. The NERC-led review panel will be comprised of a standing pool of individuals with relevant expertise from NERC and each of the Regional Entities. Individuals with relevant expertise shall be appointed by the Regional Entity senior executive (CEO, President, General Manager, etc.) and individuals with relevant expertise shall be appointed by the NERC senior executive (CEO, President, General Manager, etc.). NERC shall select the panel members for a given matter from the standing pool.

    b. Panel members for a given matter shall comply with Subsection 7 of Section 403 of the NERC ROP, shall not be employed by the Regional Entity whose determination is being reviewed or have otherwise participated in the review of the registration matter, and shall have the required technical background to evaluate registration matters.

2. With respect to review of the application of the criteria contained in the Statement of Compliance Registry Criteria Sections I through IV, the burden of proof is on NERC and the Regional Entity to demonstrate that an entity meets the Registry Criteria for registration.

3. The burden of proof with respect to the materiality test, set forth in **Appendix 5B**, *Statement of Compliance Registry Criteria*, is on the entity making the request, i.e., the entity asking to be excluded from the NCR (despite satisfying the threshold criteria)[5] and the Regional Entity seeking to include an entity in the NCR (that does not satisfy the threshold criteria).

4. The burden of proof with respect to a determination as to whether an entity's compliance obligations should be limited to only a specified sub-set of otherwise applicable Reliability Standards is on the entity requesting such treatment, provided, however, that where NERC has established clearly defined criteria for eligibility for a sub-set of applicable Reliability Standards (which may specify Requirements/sub-Requirements) and has identified the sub-set list that may apply to similarly situated entities (e.g., UFLS-Only DPs), the burden of proof to demonstrate that an entity does not meet the criteria for such a sub-set list is on the Regional Entity and NERC.

5. The entity who bears the burden of proof with respect to application of the materiality test, or a sub-set list of applicable Reliability Standards (which may specify Requirements/sub-Requirements) must submit to NERC, in writing, details of the issues and identification of the Responding Entity,[6] and the applicable Regional Entity(ies), RC, BA, PA and TOP that have (or will have upon registration of the entity) the entity whose registration status is at issue within their respective Scope of Responsibility. NERC will send a

[5] By way of example, the Registered Entity whose Deactivation request was denied by the Regional Entity bears the burden of proof (i.e., on materiality) and both requests panel review and makes the submissions required, under 6(a) and (c), unless the issue involves the Regional Entity's application of the threshold criteria. If the issue involves the Regional Entity's application of the threshold criteria, then the Regional Entity bears the burden of proof and makes the submissions required by sections 6(a) and (c), although it is the Registered Entity who makes the request for panel review.

[6] By way of example, if a Registered Entity is seeking to be deactivated based on the materiality test and therefore bears the burden of proof, then the Responding Entity is the Regional Entity. If a Regional Entity bears the burden of proof in a materiality test case, then the entity whose registration status is at issue is the Responding Entity.

notification to the Regional Entity(ies), the entity whose registration status or sub-set list treatment is at issue, and the referenced RC, BA, PA and TOP acknowledging receipt of the notification of panel review.

a. To ensure there is no confusion with respect to the rights and responsibilities of a Registered Entity during the panel review process, the notification will confirm whether the Registered Entity will remain on the NCR and will be responsible for compliance with approved Reliability Standards applicable to the function under review.

6. The panel review process timelines with respect to application of the materiality test, or sub-set list treatment of applicable Reliability Standards (which may specify Requirements/sub-Requirements) are as follows:

   a. Within 10 Days of the date of the NERC-led review panel notification, the entity with the burden of proof will provide any additional data supporting its request to NERC (who will forward to the NERC-led review panel), the Responding Entity, the applicable Regional Entity(ies), and the RC, BA, PA and TOP that has (or will have upon registration of the entity) the entity whose registration status at issue within their respective Scope of Responsibility.

   b. The Responding Entity will provide a copy of its assessment directly to all parties, as well as to NERC, within 20 Days of the date of the NERC panel review notification. If the RC, BA, PA and TOP provide an assessment, they must provide a copy to all parties, as well as NERC, within 20 Days of the date of the NERC panel review notification.

   c. The entity with the burden of proof may submit a response to the Responding Entity assessment, and any assessment submitted by the RC, BA, PA and TOP, with copies to all parties and NERC, within 30 Days of the date of the NERC panel review notification.

   d. The standard of proof in any proceeding under these procedures shall be by a preponderance of the evidence.

   e. The NERC-led review panel will render its decision within 60 Days of the final submission to the panel.

7. With respect to threshold disputes regarding application of Sections I through IV of **Appendix 5B**, *Statement of Compliance Registry Criteria*, the entity whose registration status is at issue must submit to NERC, in writing, details of the issues and identification of the applicable Regional Entity(ies), RC, BA, PA and TOP that have (or will have upon registration of the entity) the entity whose registration status is at issue within their respective Scope of Responsibility, NERC will send a notification to the Regional Entity(ies), the entity whose registration status is at issue, and the referenced RC, BA, PA and TOP acknowledging receipt of the notification of panel review.

   a. To ensure there is no confusion with respect to the rights and responsibilities of a Registered Entity during the panel review process, the notification will confirm whether the Registered Entity will remain on the NCR and will be responsible for compliance with approved Reliability Standards applicable to the function under review.

8. The panel review process timelines for threshold disputes regarding application off Sections I through IV of **Appendix 5B**, *Statement of Compliance Registry Criteria* are as follows:

   a. The entity whose registration status is at issue will provide NERC (who will forward to the NERC-led review panel), the applicable Regional Entity(ies), and the RC, BA, PA and TOP that has (or will have upon registration of the entity) the entity whose registration status at issue within their respective Scope of Responsibility, any additional data supporting its request within 10 Days of the date of the NERC panel review notification. In such a case, the Regional Entity has the burden of proof on application of the threshold criteria.

   b. The Regional Entity will provide a copy of its assessment directly to all parties, as well as to NERC, within 20 Days of the date of the NERC panel review notification. If the RC, BA, PA and TOP provide

an assessment, they must provide a copy to all parties, as well as NERC, within 20 Days of the date of the NERC panel review notification.

c. The entity whose registration status is at issue may submit a response to the Regional Entity assessment, and any assessment submitted by the RC, BA, PA and TOP, with copies to all parties and NERC, within 30 Days of the date of the NERC panel review notification.

d. The standard of proof in any proceeding under these procedures shall be by a preponderance of the evidence.

e. The NERC-led review panel will render its decision within 60 Days of the final submission to the panel.

9. In reaching a decision, the NERC-led review panel will apply the materiality test and other criteria and notes, as applicable, set forth in **Appendix 5B**, *Statement of Compliance Registry Criteria*. The NERC-led review panel ~~may~~ shall also include a review of individual and aggregate system-wide risks to, and considerations of, reliability of the BPS, as well as the BES Definition, as applicable.

10. NERC may extend the timelines for good cause shown. Requests should be sent to the Director of Compliance. NERC shall notify the entity whose registration status or sub-set list treatment is at issue and the Regional Entity of such time extensions, as well as the RC, BA, PA and TOP, of such time extensions.

11. Once a decision is made, it will be issued to the entity whose registration status or sub-set list treatment is at issue, the Regional Entity and the referenced RC, BA, PA and TOP. The decision (including its basis) will be posted on the NERC website, with confidential information redacted in accordance with Section 1500 of the NERC ROP.

12. NERC will forward within five business Days the proposed additions or changes to the NCR to the Regional Entity for review and comment.

    a. The Regional Entity has 5 business Days to respond to the proposed changes.

    b. If NERC does not receive any comments, the NCR will be revised. If NERC receives comments, NERC will work with the Regional Entity to the extent changes are needed to the NCR and will revise the NCR accordingly.

13. The BOTCC will resolve appeals of registration disputes in accordance with NERC ROP Section 500 and **Appendix 5A,** *Organization Registration and Organization Certification Manual*, Section V.

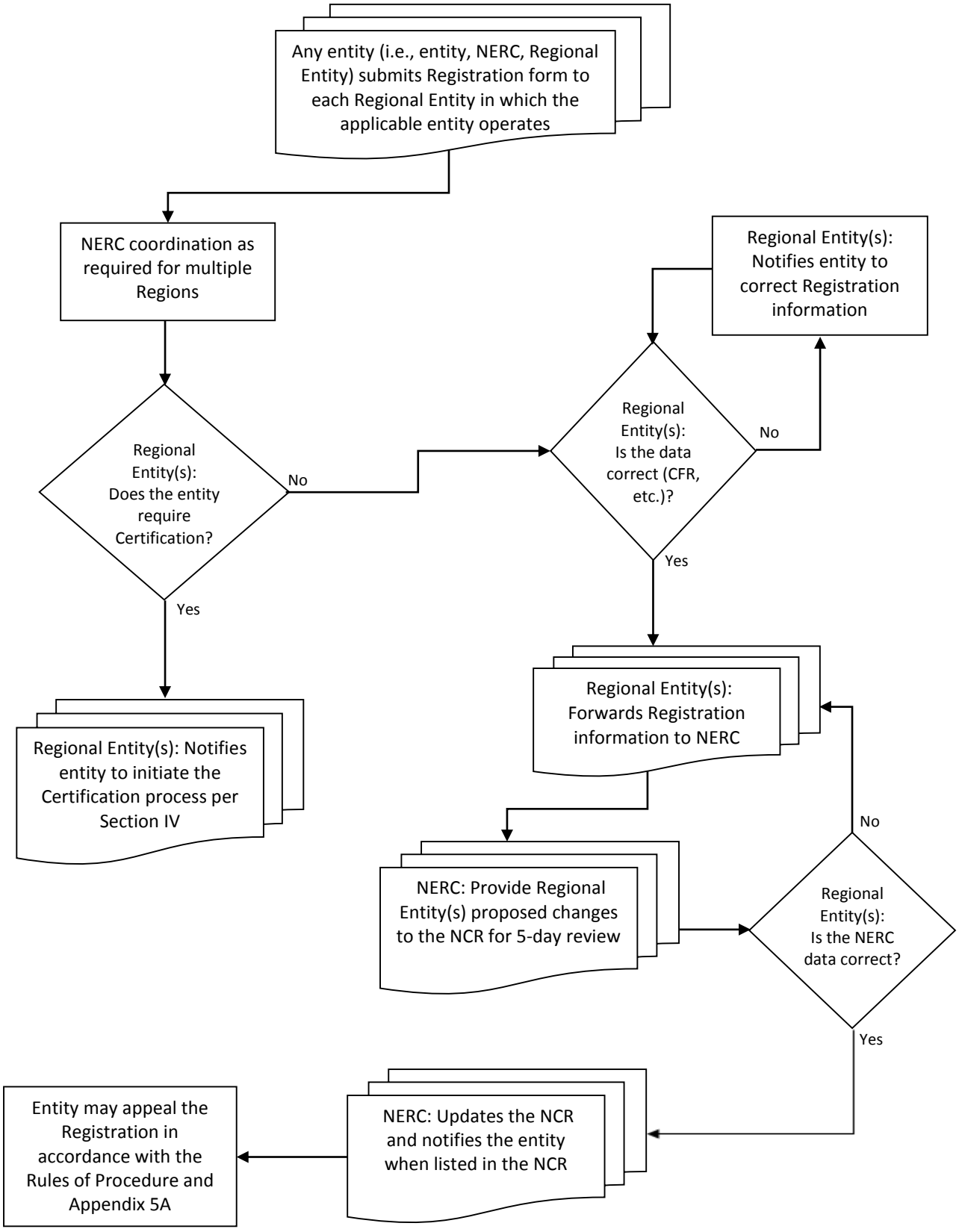

Figure 1A: Organization Registration Process Overview

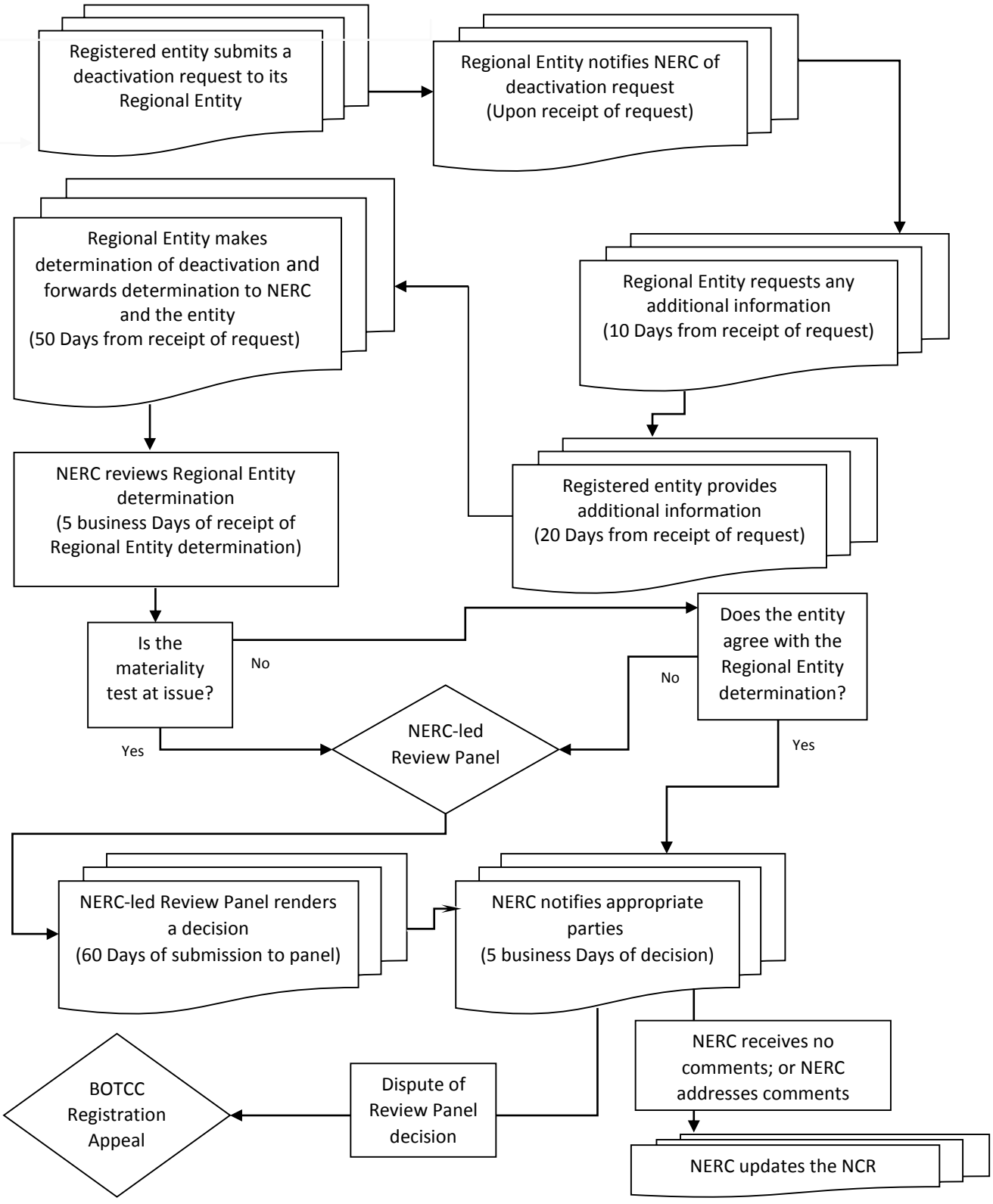

Figure 1B: Deactivation Process Overview

Section IV — Organization Certification Process

Purpose and Scope

The purpose and scope of this process is to provide guidance for completing the Certification of a new entity that will become NERC certified and registered as an RC, TOP, or BA.

Overview

See Figure 2 *Organization Certification Process Overview* for an overview of the Certification process.

Organization Certification Process

1. Certification:

   a. An entity in a single Regional Entity reliability Region shall initiate the Certification process by completing a Certification application (Certification applications are provided on each Regional Entity's website) and sending it to the Regional Entity which will manage the Certification process.

   b. An entity in multiple Regional Entity reliability Regions shall initiate the Certification process by completing a Certification application (Certification applications are provided on each Regional Entity's website) and sending it to the Regional Entities in those reliability Regions. Each Regional Entity will inform NERC of the request. The Regional Entities will determine which Regional Entity will provide the leadership to manage the Certification process.

   c. Provisional Certification Process - All RCs, BAs, and/or TOPs that were already registered and operating on June 18, 2007 become "NERC Certified" upon completion of (1) a NERC readiness evaluation (on site activities completed by the evaluation team); and (2) a CMEP Compliance Audit (on site activities completed by the Compliance Audit team) after June 18, 2007. Recertification on a periodic basis of these Registered Entities will not be required. Demonstration of ongoing satisfactory performance of applicable RC, BA, and TOP functional Requirements shall be accomplished by completion of a CMEP Compliance Audit every three years per the requirements of the NERC ROP.

2. For an entity that is not required to be certified, the Regional Entity(ies) shall reject the application and notify the entity that Certification is not required.

3. If the application is not complete or accurate, the Regional Entity will notify the entity to revise the application as needed. When the application is deemed complete and accurate, it will be accepted. The entity and the Regional Entity shall agree to a timeline including specific milestones for the Certification process.

4. The decision to certify changes to an already operating and certified Registered Entity is a collaborative decision between the affected Regional Entity(s) and NERC. NERC has the final authority regarding this decision. Items to consider for this decision include one or more of the following:

   a. Changes to a Registered Entity's Footprint or operational challenges (i.e., TLRs) due to the changes

   b. Organizational restructuring that could impact the BPS reliability

   c. Relocation of the control center

   d. Changes to Registered Entity ownership requiring major operating procedure changes

   e. Significant changes to JRO/CFR assignments or agreements changes

   f. Addition or removal of member JRO/CFR utilities or entities

g. Complete replacement of a Supervisory, Control and Data Acquisition (SCADA)/Energy Management System (EMS) system

5. The Certification process shall be completed within nine months of the date of acceptance of the application unless agreed to by all parties involved in the process and approved by NERC.

6. The Regional Entity(ies) shall notify NERC that the Certification process has begun to enable NERC to carry out its roles and responsibilities.

7. The Regional Entity will send a questionnaire with a submission deadline and a statement of expectations to all entities participating in the Certification process. These questionnaires and other related documents are located on the NERC website. The Regional Entity shall distribute questionnaires and other related documents to the following entities, as required:

   a. Entity seeking Certification.

   b. Participating BAs, RCs, and TOPs in Footprints in which the entity intends to operate or with which the entity intends to interconnect transmission Facilities.

   c. Participating TOs, TSPs, PAs, GOs, GOPs, TPs, DPs, and/or other applicable entities.

8. The Regional Entity shall assemble a CT that will be responsible for performing the activities included in the Certification process.

   a. The CT members shall adhere to NERC's confidentiality agreements for any data or information made available to the CT member through the Certification process. Team members shall not be employees of or have a direct financial interest in the entity or any of its affiliates.

   b. The Regional Entity, with concurrence of NERC, may increase or decrease the distribution of the questionnaires and other related documents based upon the complexity of the Certification.

   c. If the entity objects to any member of the CT, the entity must make that known, in writing, to the Regional Entity listing the reasons for the objection. The Regional Entity will either replace the team member or respond with written justification for keeping the member on the team.

   d. CT composition

      i. The BA CT shall consist of representatives from an existing BA, the entity's proposed RC, TOP, each affected Regional Entity, and NERC.

      ii. The RC CT shall consist of representatives from an existing RC, a BA and a TOP in the proposed RC Area, each affected Regional Entity, and NERC.

      iii. The TOP CT shall consist of representatives from an existing TOP, the entity's proposed RC, each affected Regional Entity, and NERC.

      iv. Additional CT members with expertise in the any of the NERC Compliance Registry functional areas can be added as necessary.

      v. Additional CT members from NERC or Regional Entity staff may be added as necessary.

      vi. Entities such as government representatives or other stakeholders may be observers in the Certification process.

9. Each CT member must complete the NERC auditor training prior to participation.

10. The CT will review the entity's submitted documentation and address any issues prior to the site visit.

11. The CT shall inform the entity before the on-site visit of any documentation or clarification that is necessary to support the questionnaires.

12. The entity shall identify to the CT prior to the on-site visit all Reliability Standards or Requirements/sub-Requirements which have been delegated to another entity.
    a. The CT will review the entity(ies) ability to perform those delegated Requirements/sub-Requirements or Reliability Standards.
13. The CT shall conduct at least one on-site visit to the entity's Facilities. At a minimum, the team will:
    a. Review with the entity the data collected through the questionnaires, and such data that is available only onsite;
    b. Interview the operations and management personnel;
    c. Inspect the Facilities and equipment associated with the applicable Reliability Standards referenced in the questionnaire;
    d. Request demonstration of all tools identified in the Certification process;
    e. Review documents and data including agreements, processes, and procedures identified in the Certification process;
    f. Verify operating personnel NERC Certification documents and proposed work schedules; and,
    g. Review any additional documentation resulting from inquiries arising during the site-visit.
14. The entity, in conjunction with the CT, shall attempt to resolve any deficiencies prior to issuance of the draft report.
15. The draft report is provided to the entity for review for 14 Days and any resulting comments will be assessed by the CT for possible inclusion in the report.
16. The Regional Entity(ies) may grant a time extension, not to exceed 180 Days, to the entity to allow the entity to resolve any open Certification issues.
17. The CT shall provide a Certification recommendation and identification of audit deficiencies in the final written report. All members of the CT shall have an equal voice in the Certification recommendation. This allows for a minority opinion if the review team cannot reach a consensus. The final written Certification report is distributed to NERC, the entity, and the other affected Regional Entities, as applicable.
18. The following is the format for the final report:
    - Title page
    - Table of Contents
    - Introduction – A brief discussion on the Regional Entity(ies) involved, the entity being certified, a description of the function the entity(ies) are being certified for, and a brief timeline of the Certification project.
    - CT – Provide the CT makeup.
    - Objective and Scope – Discussion on entity application (who, what, when, & how).
    - Overall Conclusion – Recommendation being made by the CT.
    - CT Findings – Any item(s) needing to be closed prior to operation that do not hinder the CT from making a recommendation.
    - Positive Observations.
    - Company History – Discussion on the applicant's company history.

- Company Details – Specific details regarding why the entity is being certified and its relationship with other entities (BAs, RCs, and TOPs etc.).
- Documentation List – Provide a list of critical documentation reviewed by the CT used to make the CT's conclusion and the documentation retention requirements.
- Attachments – Describe those attachments that are for public viewing and those that are separated from the report due to confidentiality issues such as Critical Infrastructure documentation.

19. Certification recommendation and approval.
    a. If the entity intends to operate in a single Regional Entity's reliability Region, the CT shall make a Certification recommendation to that Regional Entity. The Regional Entity shall approve or disapprove the recommendation. The Regional Entity shall notify the entity and NERC of the Certification decision.
    b. If the entity intends to operate in multiple Regional Entities, the CT shall make a Certification recommendation to all applicable Regional Entities in a single report. Certification recommendation by the Regional Entities must be unanimous. The Regional Entities shall notify the entity and NERC of the Certification decision.
    c. NERC shall approve or disapprove all final Certification recommendations and notify the entity of the decision.
20. The entity may appeal the decision in accordance with the NERC ROP and Section VI of this manual.
21. If the entity is approved for Certification, NERC shall provide the entity a Certification letter and a NERC certificate indicating that that entity is NERC certified as a BA, RC, and/or TOP as applicable.
    a. For those CFR entities that agree upon a division of compliance responsibilities for one or more Reliability Standards or Requirements/sub-Requirements, NERC shall provide all entities responsible for BA, RC and/or TOP Requirements/sub-Requirements and approved for Certification as BA, RC and/or TOP a NERC certificate indicating that those entities are NERC certified as a BA, RC, and/or TOP.
    b. NERC shall update the Compliance Registry prior to the entity(s) going operational.
22. After the entity has been awarded Certification, the Regional Entity(ies) shall notify all applicable entities as to the date that the entity may begin its operation as a certified entity. The entity must commence operation within 12 months of Certification. Failure to begin operation within the 12-month period shall require the entity to reapply for Certification.

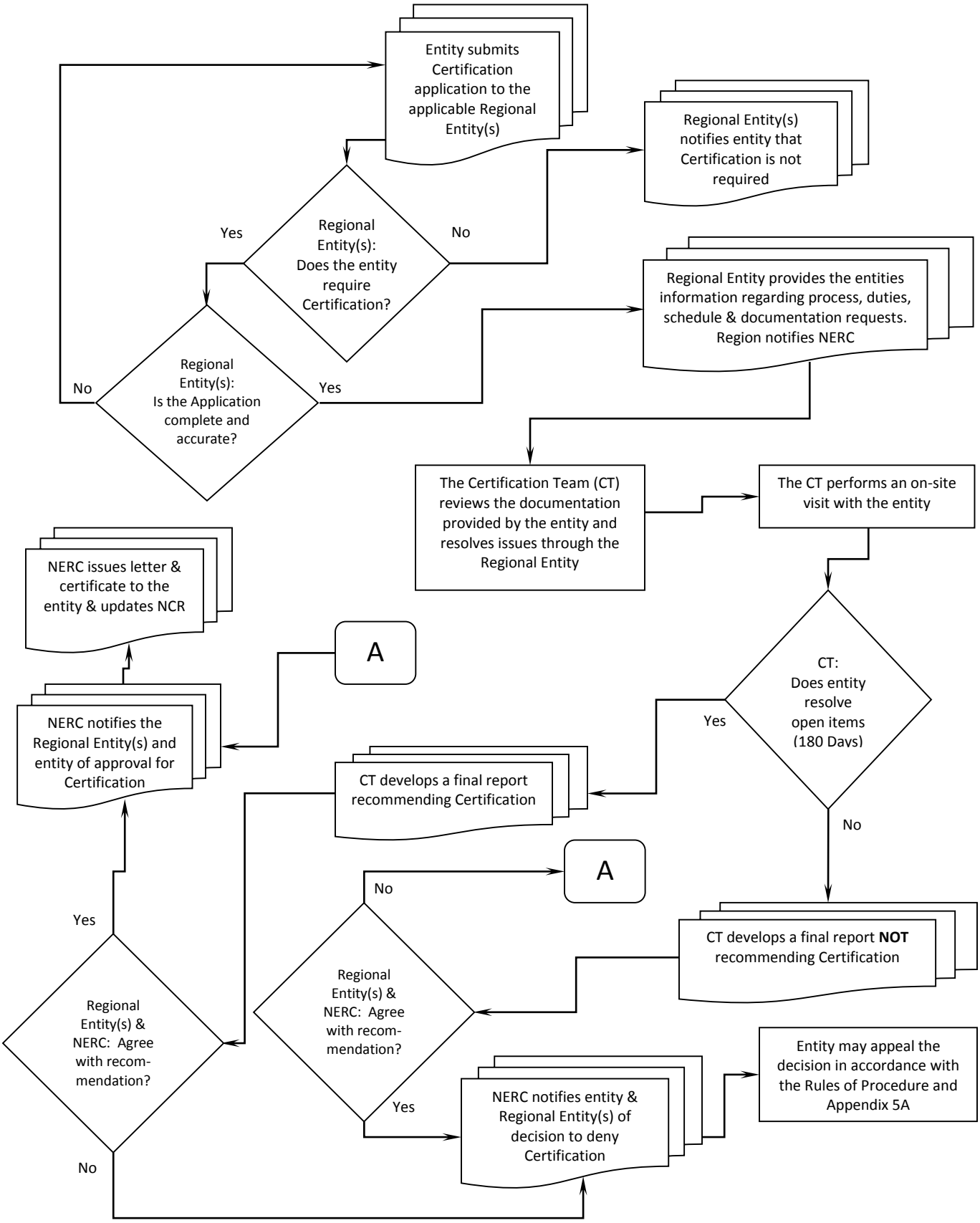

Figure 2: Organization Certification Process Overview

Section V — NERC Organization Registration Appeals Process

Purpose and Scope

This section describes the process that any organization must use to seek review of its listing and functional assignment on the NCR.

Overview

NERC has established documented procedures to ensure a fair and impartial appeals process. No one with a direct interest in a dispute may participate in the appeals process except as a party or witness. See Figure 3, *Organization Registration Appeals Process Overview*.

Organization Registration Appeals Procedure

1. Any Registered Entity included on the NCR may challenge final decisions regarding its listing, functional assignments, and determinations regarding the applicability of a sub-set of Reliability Standards (which specifies the specific Reliability Standards and may specify Requirements/sub-Requirements).
2. All registration appeals must be filed in writing to NERC, via registered mail. Appeals are sent to:

   Compliance Operations
   3353 Peachtree Road NE
   Suite 600, North Tower
   Atlanta, GA 30326
   Main: (404) 446-2560
   Facsimile: (404) 446-2595
3. Each party in the appeals process shall pay its own expenses for each step in the process.
4. A stipulation of invoking the appeals process is that the Regional Entity or Registered Entity requesting the appeal agrees that NERC (its Members, Board, committees, subcommittees, and staff), any person assisting in the appeals process, and any company employing a person assisting in the appeals process, shall not be liable for, and shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.
5. Parties retain the right to seek further review of a decision in whatever regulatory agency or court that may have jurisdiction.
6. All appeals must be received within 21 Days of receipt of the NERC determination that is being appealed. The appeal must state why the Registered Entity believes it should not be registered or should be deactivated based on the NERC ROP and the *NERC Statement of Compliance Registry Criteria* or why its compliance obligations should be limited only to a sub-set list of otherwise applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements). A copy of the appeal must be concurrently served on the Regional Entity.

7. After receipt of the appeal, the Registered Entity has a 30 day period to work with the Regional Entity to resolve the appeal, if possible. If the appeal is resolved, the Regional Entity will notify NERC with the details of the resolution and NERC will close the appeal.
8. At any time through this appeals process, a Registered Entity may agree with the decision and/or agree to close the appeal. NERC shall notify the involved parties and the NERC BOTCC that the appeal is resolved and update the NCR as applicable.
9. NERC will notify the Registered Entity and the applicable Regional Entity(ies) regarding the appeal with the following expectations:
    a. The Registered Entity will provide NERC and the applicable Regional Entity(ies) any additional data supporting its appeal within 10 Days of the date of the NERC appeal notification.
    b. The applicable Regional Entity(ies) will provide a copy of its assessment directly to the Registered Entity, as well as to NERC, within 20 Days of the date of the NERC appeal notification.
    c. The Registered Entity may submit a response to the Regional Entity(ies) assessment, with copies to the Regional Entity(ies) and NERC, within 30 Days of the date of the NERC appeal notification.
    d. To ensure there is no confusion with respect to the rights and responsibilities of the Registered Entity during the appeal process, the notification will confirm whether the Registered Entity will remain on the NERC Compliance Registry and will be responsible for compliance with approved Reliability Standards applicable to the function under appeal during the appeal.
    e. NERC may extend the timelines for good cause shown. Requests should be sent to the Director of Compliance. NERC shall notify the Registered Entity and the Regional Entity of such time extensions.
10. Hearing and Ruling by the BOTCC
    a. The BOTCC will resolve Registration disputes.
    b. The BOTCC may request additional data from NERC, the relevant Regional Entity(ies) or the Registered Entity, and prescribe the timeframe for the submitting the requested data.
    c. The BOTCC will provide a written decision regarding any appeals, along with the basis for its decision.
    d. If the BOTCC upholds the appeal, NERC will:
        - Notify the Registered Entity and Regional Entity(ies) that the appeal was granted.
        - Update the NCR.
    e. If the BOTCC does not uphold the appeal, NERC will:
        - Notify the Registered Entity and the Regional Entity(ies) that the appeal was denied.
        - The Registered Entity may appeal to Federal Energy Regulatory Commission (FERC) or another Applicable Governmental Authority within 21 Days of the notification of the decision.
    f. A record of the appeals process shall be maintained by NERC. Confidentiality of the record of the appeal will be based on the NERC ROP Section 1500.

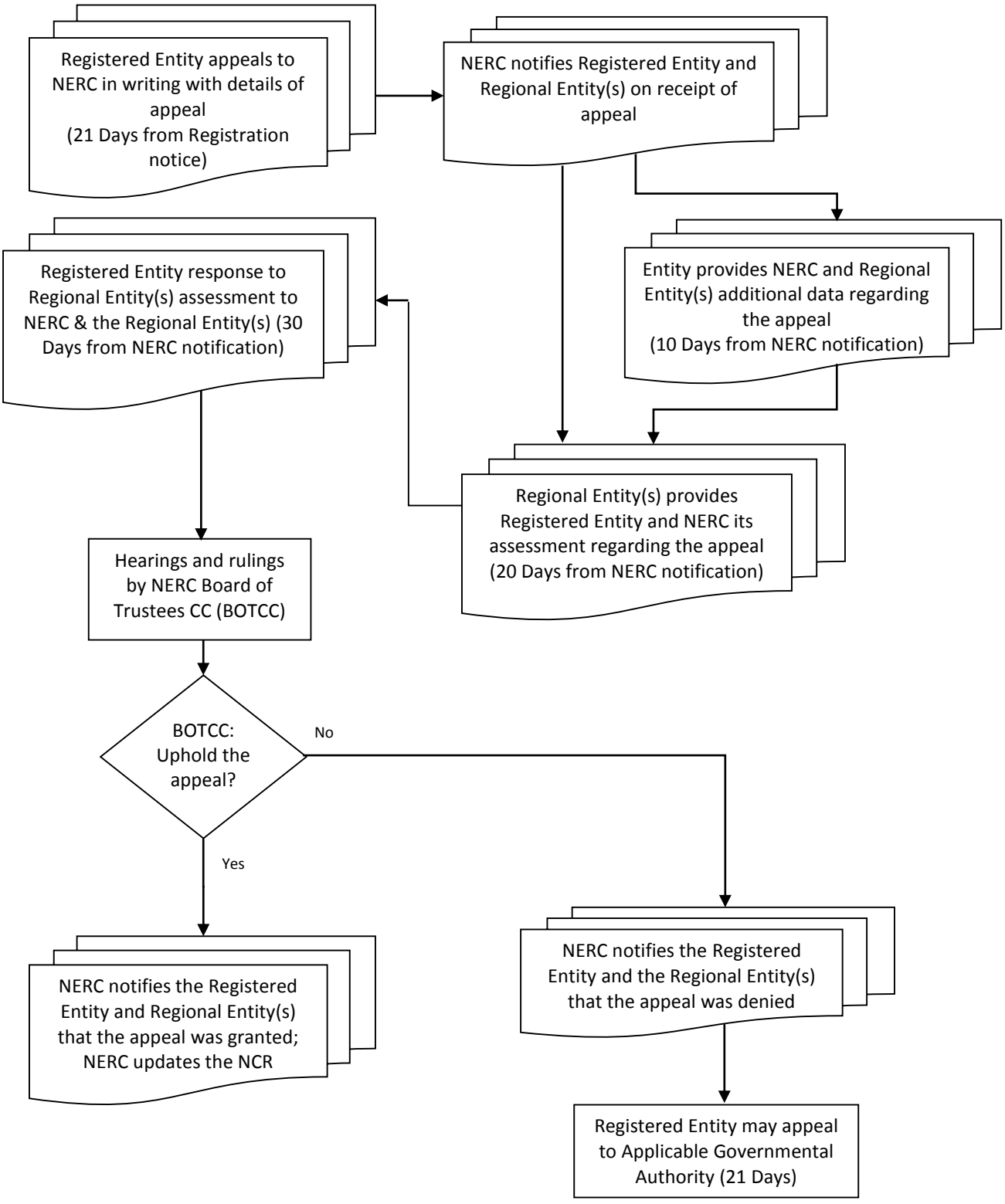

Figure 3: Organization Registration Appeals Process Overview

Section VI — NERC Organization Certification Appeals Process

Purpose and Scope

This section describes the process for an organization to appeal the Certification decision that was determined in the Certification process.

Overview

The NERC Organization Certification Program provides a key means to fulfill NERC's mission. In conducting this program, NERC has established documented procedures to ensure a fair and impartial appeals process. No one with a direct interest in a dispute may participate in the appeals process except as a party or witness. See Figure 4 *Organization Certification Appeals Process Overview*.

Organization Certification Appeals Procedure

1. Appeal for an Organization Certification Finding.
2. Any entity can appeal an organization Certification decision issued as a result of the Certification process.
3. Requirements and Conditions for Appeals.
    a. For all appeals under the NERC Organization Certification Program, the appeals process begins when an entity notifies the NERC Vice President and Director of Compliance, in writing, that it wishes to use the NERC appeals process.
        - The Director of Compliance is the main contact for all parties in all steps of the appeals process.
        - If an appeal is not filed within 21 Days of the date that the Certification report or finding is issued, or the final Regional Entity appeals process ruling is made, the finding shall be considered final and un-appealable.
    b. Each party in the appeals process shall pay its own expenses for each step in the process.
    c. A stipulation of invoking the appeals process is that the Regional Entity or entity requesting the appeal agrees that NERC (its Members, Board, committees, subcommittees, and staff), any person assisting in the appeals process, and any company employing a person assisting in the appeals process, shall not be liable, and shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.
    d. Parties retain the right to seek further review of a decision in whatever regulatory agency or court that may have jurisdiction.
4. At any time through this appeals process, an entity may withdraw its appeal.
5. Hearing and Ruling by the Compliance and Certification Committee.
    a. Within 28 Days of receiving notice from the NERC Director of Compliance, the CCC will conduct a hearing where all the parties or representatives of the disputing parties will present the issue in question, in accordance with CCC procedure CCCPP-005, *Hearing Procedures for Use in Appeals of Certification Matters*, which is incorporated in **Appendix 4E** of the ROP.
    b. If the appeal is upheld, NERC notifies the entity and Regional Entity(s), updates the NCR, and issues any appropriate letter and certificate to the entity.
    c. If the appeal is denied, NERC notifies the entity and Regional Entity(s).

6. Hearings and Ruling by the BOTCC.

   a. The BOTCC will be asked to resolve a dispute related to the NERC Organization Certification Program if any party to the appeal contests the CCC final order.

   b. The BOTCC may request additional data from NERC, Regional Entity(s) or the entity and prescribe the timeframe for the submitting the requested data.

   c. At the next regularly scheduled BOTCC meeting, or at a special meeting if the Board determines it is necessary, the Chairman of the CCC will present a summary of the dispute and the actions taken to the BOTCC.

      - Each party will have an opportunity to state its case.
      - The BOTCC will then rule on the dispute.

   d. If the BOTCC upholds the appeal, NERC will:

      - Notify the entity and the Regional Entity(ies) that the appeal was upheld.
      - Update the NCR.
      - Issue a Certification letter and a certificate to the entity as applicable.

   e. If the BOTCC does not uphold the appeal, NERC will notify the entity and the Regional Entity(ies) that the appeal was denied.

      - The entity may appeal to Applicable Governmental Authorities within 21 Days of the issuance of the decision.

   f. A record of the appeals process shall be maintained by NERC and available upon request. Confidentiality of the record of the appeal will be based on the NERC ROP Section 1500.

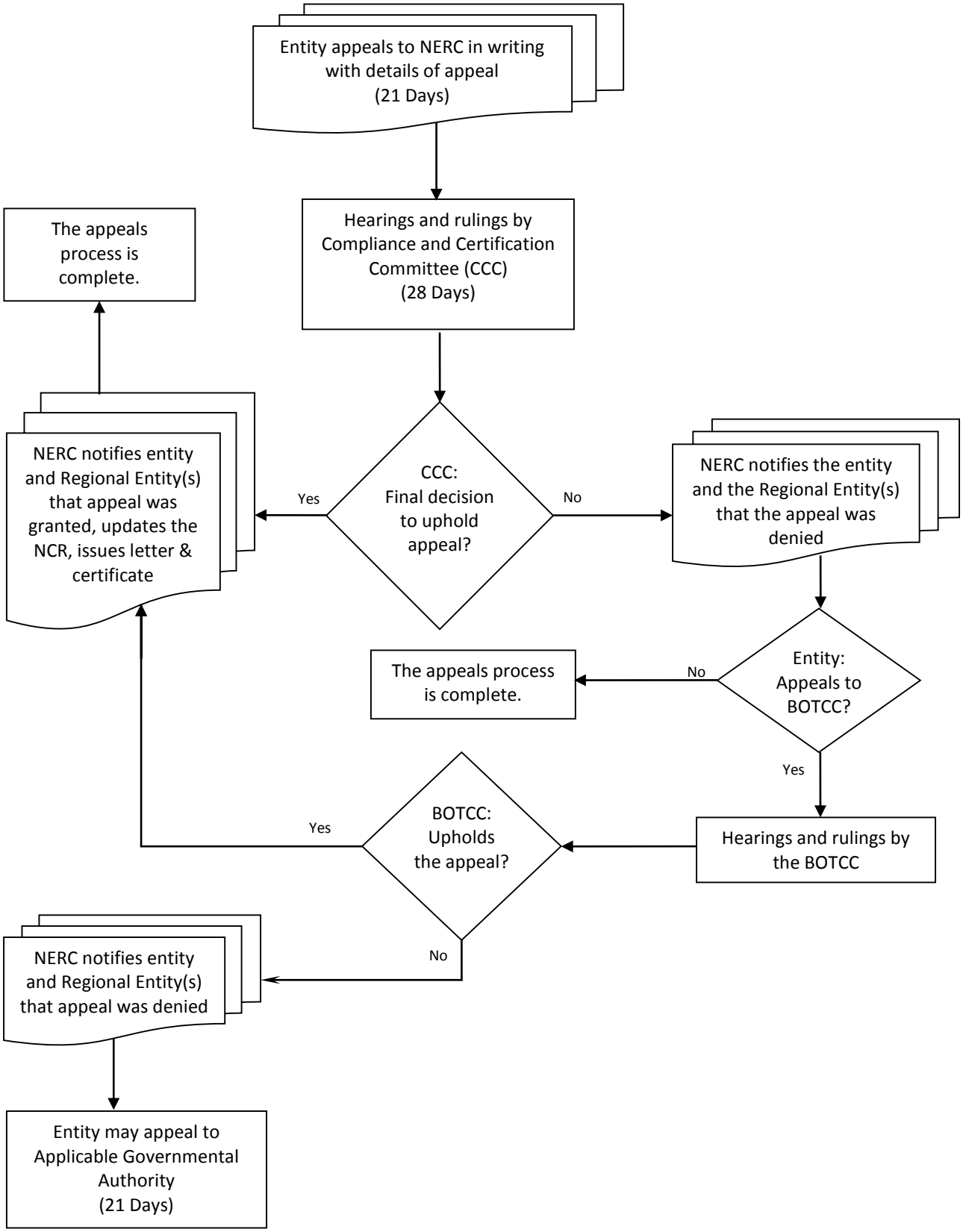

Figure 4: Organization Certification Appeals Process Overview

Definitions

Capitalized terms used in this Appendix shall have the definitions set forth in Appendix 2 of the ROP. For convenience of reference, definitions used in this Appendix are also set forth below:

NERC Organization Certification	The process undertaken by NERC and a Regional Entity to verify that a new entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator, and/or Reliability Coordinator.
Compliance and Certification Manager	The individual/individuals within the Regional Entity that is/are responsible for monitoring compliance of entities with applicable NERC Reliability Standards.
Days	Days as used in the Registration and Certification processes are defined as calendar days.
Footprint	The geographical or electric area served by an entity.
Functional Entity	An entity responsible for a function that is required to ensure the Reliable Operation of the electric grid as identified in the NERC Reliability Standards.
Mapping	The process of determining whether a Regional Entity's Footprint is being served by Registered Entities.
NERC Identification Number (NERC ID)	A number given to NERC Registered Entities that will be used to identify the entity for certain NERC activities. Corporate entities may have multiple NERC IDs to show different corporate involvement in NERC activities.
Regional Entity	An entity having enforcement authority pursuant to 18 C.F.R. § 39.8.
Registration	Processes undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region.
Coordinated Functional Registration (CFR)	Where two or more entities (parties) agree in writing upon a division of compliance responsibility among the parties for one or more Reliability Standard(s) applicable to a particular function, and/or for one or more Requirement(s)/sub-Requirement(s) within particular Reliability Standard(s).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix 5B[1]
Statement of Compliance Registry Criteria

Revision 5.2

Effective: ~~March 19, 2015~~DATE

[1] Highlighted text reflects incremental changes made in response to stakeholder feedback.

Statement of Compliance Registry Criteria (Revision 5.2)

Summary

This document describes how the North American Electric Reliability Corporation (NERC) will identify organizations that may be candidates for Registration and assign them to the Compliance Registry.

NERC and the Regional Entities[2] have the obligation to identify and register all entities that meet the criteria for inclusion in the Compliance Registry, as further explained in the balance of this document.

Organizations will be responsible to register and to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the Bulk Power System (BPS), perform a function listed in the functional types identified in Section II of this document, and are material to the Reliable Operation of the interconnected BPS as defined by the criteria and notes set forth in this document. NERC will apply the following principles to the Compliance Registry:

- In order to carry out its responsibilities related to enforcement of Reliability Standards, NERC must identify the owners, operators, and users of the BPS who have a material impact[3] on the BPS through a Compliance Registry. NERC and the Regional Entities will make their best efforts to identify all owners, users and operators who have a material impact on the BPS in order to develop a complete and current Compliance Registry list. The Compliance Registry will be updated as required and maintained on an on-going basis.
- Organizations listed in the Compliance Registry are responsible and will be monitored for compliance with applicable mandatory Reliability Standards. They will be subject to NERC's and the Regional Entities' Compliance Monitoring and Enforcement Programs.
- NERC and Regional Entities will not monitor nor hold those not in the Compliance Registry responsible for compliance with the Reliability Standards. An entity which is not initially placed on the Compliance Registry, but which is identified subsequently as having a material impact, will be added to the Compliance Registry. Such entity will not be subject to a sanction or Penalty by NERC or the Regional Entity for actions or inactions prior to being placed on the Compliance Registry, but may be required to comply with a Remedial Action Directive or Mitigation Plan in order to become compliant with applicable Reliability Standards. After such entity has been placed on the Compliance Registry, it shall be responsible for complying with Reliability Standards and may be subject to sanctions or Penalties as well as any Remedial Action Directives and Mitigation Plans required by the Regional Entities or NERC for future violations, including any failure to follow a Remedial Action Directive or Mitigation Plan to become compliant with Reliability Standards.
- Required compliance by a given organization with the Reliability Standards will begin the later of (i) inclusion of that organization in the Compliance Registry and (ii) approval by the Applicable Governmental Authority of mandatory Reliability Standards applicable to the registered entity.

[2] The term "Regional Entities" includes Cross-Border Regional Entities, that have footprints in the U.S., Canada and Mexico, as applicable. Applicable Governmental Authorities in Canadian jurisdictions may have adopted their own Rules of Procedure and Compliance Registry requirements. Registered Entities may be subject to the Compliance Monitoring and Enforcement Programs (CMEP) in their respective jurisdictions, in accordance with applicable laws and regulations.

[3] The criteria for determining whether an entity will be placed on the Compliance Registry are set forth in the balance of this document. At any time a person may recommend in writing, with supporting reasons, to the Director of Compliance (or an equivalent position) that an organization be added to or removed from the Compliance Registry, pursuant to NERC Rules of Procedure Section 501.1.3.5.

Entities responsible for funding NERC and the Regional Entities have been identified in the budget documents filed with FERC.[4] Presence on or absence from the Compliance Registry has no bearing on an entity's independent responsibility for funding NERC and the Regional Entities.

Background

In 2005, NERC and the Regional Entities conducted a voluntary organization registration program limited to Balancing Authorities, Planning Authorities, regional reliability organizations, Reliability Coordinators, Transmission Operators, and Transmission Planners. The list of the entities that were registered constitutes what NERC considered at that time as its Compliance Registry.

NERC initiated a broader program to identify additional organizations potentially eligible to be included in the Compliance Registry and to confirm the information of organizations currently on file, taking into account the following considerations:

- As of July 20, 2006, NERC was certified as the Electric Reliability Organization (ERO) created for the U.S. by the Energy Policy Act of 2005 (EPAct) and FERC Order No. 672. NERC has received similar recognition by Canadian authorities in their respective jurisdictions.
- FERC Order No. 672 directs that owners, operators and users of the BPS in the U.S. shall be registered with the ERO and the appropriate Regional Entities.
- As the ERO, NERC has filed its current Reliability Standards with FERC and with Canadian authorities. As accepted and approved by FERC and appropriate Canadian authorities, the Reliability Standards are no longer voluntary, and organizations that do not fully comply with them may face Penalties or other sanctions, in accordance with applicable laws, regulations and orders of Applicable Governmental Authorities.
- NERC's Reliability Standards include compliance Requirements for additional reliability function types beyond the six types registered by earlier registration programs.
- Based on selection as the ERO, NERC's Organization Registration program[5] is the means by which NERC and the Regional Entities plan, manage and execute Reliability Standard compliance oversight of owners, operators, and users of the BPS.
- Organizations listed in the Compliance Registry are subject to NERC's and the Regional Entities' Compliance Monitoring and Enforcement Programs.

Statement of Issue

As the ERO, NERC intends to comprehensively and thoroughly protect the reliability of the grid. To support this goal NERC will include in its Compliance Registry each entity that NERC concludes can materially impact the reliability of the BPS.

NERC wishes to identify those entities that may need to be listed in its Compliance Registry. Identifying these organizations is necessary and prudent for the purpose of determining resource needs, both at the

[4] Budget documents are submitted to Applicable Governmental Authorities in Canada for information.
[5] *See* NERC ERO Application; Exhibit C; Section 500 – Organization Registration and Certification.

NERC and Regional Entity level, and for communicating with these entities regarding their potential responsibilities and obligations. NERC and the Regional Entities believe that candidate entities can be identified at any time, as and when needed. The Compliance Registry is available on NERC's website.

Resolution

The potential costs and effort of registering every organization potentially within the scope of "owner, operator, and user of the BPS," while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so.

NERC and the Regional Entities have identified two principles they believe are key to the entity selection process. These are:

1. There needs to be consistency between Regions and across the continent with respect to which entities are registered; and
2. Any entity reasonably deemed material to the reliability of the BPS will be registered, irrespective of other considerations.

To address the second principle the Regional Entities, working with NERC, will identify and register any entity they deem material to the reliability of the BPS.

In order to promote consistency, NERC and the Regional Entities use the following criteria as the basis for determining whether particular entities should be identified as candidates for Registration. All organizations meeting or exceeding the criteria will be identified as candidates.

The following four groups of criteria (Sections I-IV) plus the statements in Section V will provide guidance regarding an entity's Registration status:

- Section I determines if the entity is an owner, operator, or user of the BPS and, hence, a candidate for organization Registration.
- Section II uses NERC's current functional type definitions to provide an initial determination of the functional types for which the entities identified in Section I should be considered for Registration.
- Section III lists the criteria regarding smaller entities; these criteria can be used to forego the Registration of entities that were selected to be considered for Registration pursuant to Sections I and II and, if circumstances change, for later removing entities from the Compliance Registry that no longer meet the relevant criteria.
- Section IV — additional criteria for joint Registration. Joint Registration criteria may be used by joint action agencies, generation and transmission cooperatives and other entities which agree upon a clear division of compliance responsibility for Reliability Standards by written agreement. Rules pertaining to joint Registration and Joint Registration Organizations, as well as Coordinated Functional Registrations, are now found in Sections 501, 507 and 508 of the NERC Rules of Procedure.

I. Entities that use, own or operate Elements of the Bulk Electric System (BES) as established by NERC's approved definition of BES below are (i) owners, operators, and users of the BPS and (ii) candidates for Registration:

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- ***I1*** *- Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.*
- ***I2*** *- Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:*
  - *a) Gross individual nameplate rating greater than 20 MVA. Or,*
  - *b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.*
- ***I3*** *- Blackstart Resources identified in the Transmission Operator's restoration plan.*
- ***I4*** *- Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:*
  - *a) The individual resources, and*
  - *b) The system designed primarily for delivering capacity from the point where those resources aggregate to a greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.*
- ***I5*** *- Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.*

Exclusions:

- ***E1*** *- Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:*
  - *a) Only serves Load. Or,*
  - *b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,*
  - *c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 – The presence of a contiguous loop operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- ***E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.*
- ***E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:*

  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

  b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

  c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- ***E4** - Reactive Power devices installed for the sole benefit of a retail customer(s).*

  Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

II. Entities identified in Section I above will be categorized as Registration candidates who may be subject to Registration under one or more appropriate Functional Entity types based on a comparison of the functions the entity normally performs against the following function type definitions: [6]

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a

[6] Exclusion: An entity will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, including bilateral agreements and Sections 501, 507 and 508 of the NERC Rules of Procedure.

Function Type	Acronym	Definition/Discussion
		Balancing Authority Area, and supports Interconnection frequency in real-time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage. Note: As provided in Section III.b.1 and Note 5 below, a Distribution Provider entity shall be an Underfrequency Load Shedding (UFLS)-Only Distribution Provider if it is the responsible entity that owns, controls or operates UFLS Protection System(s) needed to implement a required UFLS program designed for the protection of the BES, but does not meet any of the other registration criteria for a Distribution Provider.
Generator Operator	GOP	The entity that operates generating Facility(ies)and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	GO	Entity that owns and maintains generating Facility(ies).
~~Load-Serving Entity~~	~~LSE~~	~~Secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.~~
Planning Authority/ Planning Coordinator	PA/PC	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the Reliable Operation of the BES, has the Wide Area view of the BES, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

Function Type	Acronym	Definition/Discussion
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes), then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific Loads (customer demand and energy requirements) within a Planning Authority area.
Transmission Owner	TO	The entity that owns and maintains transmission Facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.

III. Except as provided in Section V and the Notes to the Criteria below, entities identified in Section II above as being subject to Registration as a Distribution Provider should be included in the Compliance Registry for these functions only if they meet any of the criteria listed below:

~~III(a) Load-Serving Entity:~~

~~III.a.1 Load-Serving Entity peak Load is > 25 MW and is directly connected to the Bulk Power (>100 kV) System, or;~~

~~III.a.2 Load-Serving Entity is designated as the responsible entity for Facilities that are part of a required UFLS program designed, installed, and operated for the protection of the BPS, or;~~

~~III.a.3 Load-Serving Entity is designated as the responsible entity for Facilities that are part of a required Undervoltage Load Shedding (UVLS) program designed, installed, and operated for the protection of the BPS.~~

~~*[Exclusion: A Load-Serving Entity will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a Load-Serving Entity, Balancing Authority, Transmission Operator, generation and transmission cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*~~

~~III.a.4 Distribution Providers registered under the criteria in III.b.1 or III.b.2 will be registered as a Load Serving Entity (LSE) for all Load directly connected to their distribution facilities.~~

~~*[Exclusion: A Distribution Provider will not be registered based on this criterion if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a Load-Serving Entity, Balancing Authority, Transmission Operator, generation and transmission cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*~~

~~III(b)~~III(a) Distribution Provider:

~~III.b.1~~III.a.1 Distribution Provider system serving >75 MW of peak Load that is directly connected to the BES;[7] or

~~III.b.2~~III.a.2 Distribution Provider is the responsible entity that owns, controls, or operates Facilities that are part of any of the following Protection Systems or programs designed, installed, and operated for the protection of the BES:[8]

- a required Undervoltage Load Shedding (UVLS) program and/or
- a required Special Protection System or Remedial Action Scheme and/or
- a required transmission Protection System; or

III.~~b~~a.3 Distribution Provider that is responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs) pursuant to an executed agreement; or

III.~~b~~a.4 Distribution Provider with field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks.

III(~~c~~b) Distribution Provider with UFLS-Only assets (referred to as "UFLS-Only Distribution Provider")

[7] Ownership, control or operation of UFLS Protection System(s) needed to implement a required UFLS Program designed for the protection of the BES does not affect an entity's eligibility for registration pursuant to III.~~b~~a.1.

[8] As used in Section III.~~b~~a.2, "protection of the Bulk Electric System" means protection to prevent instability, Cascading, or uncontrolled separation of the BES and not for local voltage issues (UVLS) or local line loading management (Special Protection System) that are demonstrated to be contained within a local area.

III.~~c~~b.1 UFLS-Only Distribution Provider does not meet any of the other registration criteria in Sections III(a~~b~~)(1)-(4) for a Distribution Provider; and

III.~~c~~b.2 UFLS-Only Distribution Provider is the responsible entity that owns, controls, or operates UFLS Protection System(s) needed to implement a required UFLS Program designed for the protection of the BES.

The Reliability Standards applicable to UFLS-Only Distribution Providers are: (1) PRC-005,[9] PRC-006-1, PRC-006-2 and (2) any regional Reliability Standard whose purpose is to develop or establish a UFLS Program [PRC-006-NPCC-1 and PRC-006-SERC-01]. Reliability Standards that apply to Distribution Providers will not apply to UFLS-Only Distribution Providers, unless explicitly stated in the applicability section of these Reliability Standards and in future revisions and/or versions.

IV. Joint Registration Organization, Coordinated Functional Registration and applicable Member Registration.

Pursuant to FERC's directive in paragraph 107 of Order No. 693, NERC's rules pertaining to joint Registrations and Joint Registration Organizations, as well as Coordinated Functional Registrations, are now found in Section 501, 507 and 508 of the NERC Rules of Procedure.

V. If NERC or a Regional Entity encounters an organization that is not listed in the Compliance Registry, but which should be subject to the Reliability Standards, NERC or the Regional Entity is obligated and will initiate actions to add that organization to the Compliance Registry, subject to that organization's right to challenge as provided in Section 500 of NERC's Rules of Procedure and as described in Note 3 below.

Notes to the Registry Criteria in Sections I-V

1. The above are general criteria only. The Regional Entity considering Registration of an organization not meeting (e.g., smaller in size than) the criteria may propose Registration of that organization if the Regional Entity believes and can reasonably demonstrate[10] that the organization is a BES owner, or operates, or uses BES assets, and is material to the reliability of the BES. Similarly, the Regional Entity may exclude an organization that meets the criteria described above as a candidate for Registration if it believes and can reasonably demonstrate to NERC that the BES owner, operator, or user does not have a material impact on the reliability of the BES. Such decisions must be made in accordance with Section V of Appendix 5A to the NERC Rules of Procedure. In order to ensure a consistent approach to assessing materiality, a non-exclusive set of factors ("materiality test") for consideration is identified below; however, only a sub-set of these factors may be applicable to particular functional registration categories:

   a. Is the entity specifically identified in the emergency operation plans and/or restoration plans of an associated Reliability Coordinator, Balancing Authority, Generator Operator or Transmission Operator?

[9] Four versions of PRC-005 are currently in various stages of Commission approval and standard development. For the period that each is in effect, PRC-005-2(ii), PRC-005-3(i), PRC-005-3(ii), PRC-005-4, PRC-005-5, and PRC-005-6 will apply to an entity included on the NCR as a UFLS-Only Distribution Provider during that period.

[10] The reasonableness of any such demonstration will be subject to review and remand by NERC itself, or by any Applicable Governmental Authority, as applicable.

b. Will intentional or inadvertent removal of an Element owned or operated by the entity, or a common mode failure of two Elements as identified in the Reliability Standards (for example, loss of two Elements as a result of a breaker failure), lead to a reliability issue on another entity's system (such as a neighboring entity's Element exceeding an applicable rating, or loss of non-consequential load due to a single contingency). Conversely, will such contingencies on a neighboring entity's system result in Reliability Standards issues on the system of the entity in question?

c. Can the normal operation, misoperation or malicious use of the entity's cyber assets cause a detrimental impact (e.g., by limiting the operational alternatives) on the operational reliability of an associated Balancing Authority, Generator Operator or Transmission Operator?

d. Can the normal operation, Misoperation or malicious use of the entity's Protection Systems (including UFLS, UVLS, Special Protection System, Remedial Action Schemes and other Protection Systems protecting BES Facilities) cause an adverse impact on the operational reliability of any associated Balancing Authority, Generator Operator or Transmission Operator, or the automatic load shedding programs of a PC or TP (UFLS, UVLS)?

2. An organization not identified using the criteria, but wishing to be registered, may request that it be registered. For further information refer to: NERC Rules of Procedure, Section 500 – Organization Registration and Certification; Part 1.3.

3. An organization may challenge its Registration within the Compliance Registry. NERC or the Regional Entity will provide the organization with all information necessary to timely challenge that determination including notice of the deadline for contesting the determination and the relevant procedures to be followed as described in the NERC Rules of Procedure; Section 500 – Organization Registration and Certification.

4. If an entity is part of a class of entities excluded based on any of the criteria above as individually being unlikely to have a material impact on the reliability of the BES, but that in aggregate have been demonstrated to have such an impact it may be registered for applicable Reliability Standards and Requirements irrespective of other considerations, in accordance with laws, regulations and orders of an Applicable Governmental Authority.

5. NERC may limit the compliance obligations of a given entity registered for a particular function or similarly situated class of entities, as warranted based on the particular facts and circumstances, to a sub-set list of Reliability Standards (which may specify Requirements/sub-Requirements).

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2015 NPCC Compliance Committee Meetings (as of 1/14/15)

January 14…conference call

February 18…conference call

March 17-18 (Tue, Weds) at NextEra, Juno Beach, FL

April 15…conference call

May 13…conference call

May 19-21 Compliance Workshop (Tue-Thurs) Newport, RI Marriott.
(Week before the Memorial Day holiday)

June 16-17 (Tues, Weds) at IESO, Toronto.

July 15…CC conference call

August 19…CC conference call

September 22, 23 (Tues, Weds)…at NPCC, NYC
(Rescheduled from 9/15-9/16 on the Jan 2015 CC Call)

October 14…CC conference call

November…no conference call

November 10-12 Compliance Workshop (Tue – Thurs) Westchester, NY
(Date moved from 11/17-11/19 in December 2014 due to GRIDEX III conflict)

December 3, 4 (Thus, Fri)…at Albany, NY Marriott– after NPCC annual meetings.

As of 1/14/15